FORTE BUSINESS SOLUTIONS LTD.

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Northern Alberta Development Council

Electric Power Generation Options for Northern Alberta's Municipalities, Organizations and Residents

Executive Summary

The focus of this initiative is to review Northern Alberta's electric power needs; opportunities and challenges regarding power generation and distribution; and possible initiatives that could be undertaken by municipalities, organizations and individuals. The study examines:

- Electricity in Alberta as a whole (due to the provincial nature of the electricity system), as well as Northern Alberta specifically;
- Options and opportunities in Northern Alberta;
- Barriers to development; and
- Next steps and recommendations.

This study does not address large complex options such as nuclear power or large-scale hydroelectric projects, which are beyond the scope of resources in Northern Alberta to implement independently.

The Alberta Electricity Market

The Alberta electricity system is unique relative to other North American jurisdictions as a result of a number of factors including:

- Industrial power consumers require 60% of Alberta's electricity, compared to less than 35% in most jurisdictions;
- Alberta peak demand occurs in the winter months and is relatively low at 125% of the average annual demand. Most jurisdictions have peak demands that are in the summer at 150% of average demand levels. This is predominantly a result of Alberta industrial power consumers using electricity 24 hours a day, 7 days a week at fairly consistent levels; and
- Price volatility is largely based on uncertain supply issues, such as generator shutdowns and wind power coming on and off the system, unlike other jurisdictions where volatility is primarily influenced by weather-related demand variations.

Electric power generation and retail services are competitive, while the transmission and distribution of electric power are regulated. Generators look to the AESO hourly market price signals to determine whether to make investments in new generation projects.

The Alberta Electric System Operator (AESO) runs an hourly energy market to determine which generators will operate to put electricity into the electric grid in each hourly time interval, and what price the generators will earn for doing so.

Alberta has an "energy-only" market, where generators are paid for their output, (electricity), on an hourly basis and do not receive any other out-of-market compensation, such as fixed availability payments (sometimes called "capacity payments"). This energy-only nature of the market drives opportunities and creates obstacles.

The AESO hourly market was originally developed in 1995 as a mechanism to dispatch large-scale baseload generators, such as the coal facilities west of Edmonton. The hourly prices resulting from this mechanism have experienced added volatility as a result of new natural gas facilities, volatile natural gas pricing and wind generation that has been constructed over the past ten years.

The result is that the current price signals are relatively ineffective in their ability:

- To incent energy efficiency and demand response among consumers;
- To provide effective incentives for investments in renewable and alternate fuels;
- To recognize the value of regional-based generation projects.

To some extent, these concerns can be addressed by greater use of contracting between market participants, outside of the hourly market. One of the major opportunities for Northern Alberta is to promote greater use of contracts that encourage recognition of value for energy efficiency, carbon offsets from renewables, and location credits for regional generation.

Energy Conservation

Compared to other jurisdictions, Alberta has reduced flexibility for conservation because much of the consumption is from industrial loads, and peak loads occur in the winter months. Other jurisdictions with higher percentages of residential and commercial loads, and with summer peak demand can easily reduce consumption. For example they employ programs to shut off air conditioning when demand and prices rise substantially.

There are various categories of energy conservation that may be considered from a policy perspective, including: energy efficiency, demand response, fuel switching and self-generation. Elements of each of these energy conservation options can be viable economic solutions with appropriate incentives. These incentives need to recognize location value and carbon-reduction benefits. Alberta Energy, the AESO and industry need to coordinate actions if success is to be achieved.

Alberta Energy is developing both energy efficiency and renewable energy programs that are intended to meet the objectives of the Provincial Energy Strategy set out in December 2008. One of these programs is the Advanced Metering Infrastructure (AMI or "smart metering") initiative aimed at residential, small commercial and farm customers. The objective is to provide better measurement of electricity consumption, which will allow for wiser use of electricity.

Unfortunately, at the current time, there are no electricity retailers in Alberta specializing in energy efficiency programs that use price as an economic driver to conservation. This will make the AMI program objectives more difficult to meet. Achieving energy efficiency including conservation and local intermediate-scale generation from farm, residential and small commercial consumers may require regional programs that are based on economic drivers and incentives other than energy pricing to be successful.

Northern Alberta Supply and Demand

For electricity planning purposes, Northern Alberta is generally reviewed as two separate planning areas: the Northeast region (area east of Edmonton and north of Highway 16 and includes the eastern oilsands area) and the Northwest region (west of Edmonton, north of Highway 16 and includes Peace River area).

The *Northeast region* has been a high growth area, and will continue to experience growth in electricity demand. This is primarily due to industrial projects in the oilsands and forestry sectors.

Northeast supply will continue to grow with co-generation projects (which provide both steam and power) being developed to support the oilsands industry. Current government plans are to encourage the building of two large, 500 kV transmission lines from the Heartland area to Fort McMurray as conditions warrant such expansion. The AESO has been directed to initiate the addition of a 240 kV line into the Fort McMurray area by 2014.

The *Northwest region* is expected to sustain normal load growth in electricity demand in the near future. Currently, the region has significantly more demand than local generation, resulting in transfers from Lake Wabamun and Fort McMurray generation. The Northwest also has some transmission constraint issues, which limit the amount of electricity that can be brought in from other regions, and voltage support concerns, which make the system less stable and reliable.

Current transmission upgrades to the Northwest will alleviate these constraints by 2011; however, the supply/demand balance for the region remains a major planning concern.

Encouragement of regional generation projects can offset the potential growth in demand from industry, oil and gas development and growth in the Fort Nelson, BC area served by Alberta.

Electricity Generation Development

Three key factors will influence future generation development in Alberta:

- Implications of carbon offset pricing for traditional coal development;
- Long-term prices for natural gas and their impact on co-generation and natural gas combined cycle plant development; and
- The long-term pricing structure for power contracts in Alberta.

There are various fuel alternatives open to Alberta, including wind power, hydro, biomass and landfill gas, geothermal and co-generation. Electricity generation investment costs, operating costs, revenues and possible incentive schemes need to be considered when determining whether projects are viable.

As part of this report, analysis was undertaken, using a Natural Resources Canada software tool (RETScreen) to examine some of the clean generation options for Northern Alberta. With current market conditions, the most viable generation option for Northern Alberta continues to be large-scale natural gas combined cycle facilities, most likely in the Fort McMurray area.

Commercial-scale wind power projects appear to be marginally-economic, should electricity price levels rise to the $80/MWh range. These projects are better situated in the Northwest, due to a stronger wind regime. Location-specific wind studies would need to be undertaken as well as a careful assessment of available transmission capacity before any such projects could be undertaken. The wind regimes in the north are not as strong as southern and central Alberta and as such, may have difficulty in competing for investment capital against other Alberta wind projects.

Other smaller scale commercial renewable projects such as green hydro, landfill gas and biogas projects appear to have positive economics given the right location and access to value recognition for carbon offsets. Again, these projects would need specific inducements to proceed, as the current Alberta market structure will not support their natural evolution.

Solar Photovoltaic (PV) projects appear to be too costly and would have limited power producing capabilities in winter months relative to winter peaking demand. Price levels to make solar PV economic would need to exceed $500/MWh at the current costs of solar panels.

Micro-generation Projects

Micro-generation projects are small-scale (with a capacity of one megawatt or less) and are connected to the distribution system or operated as offsets to non-grid-connected isolated generation. These projects use renewable or alternative fuel sources and have energy output intended to meet all or a portion of the customer's electricity needs.

In terms of micro-generation project opportunities, both small-scale wind power and hydro could be developed in isolated areas with no access to the power grid, and only expensive alternatives (such as imported diesel) available to the area. Otherwise, these projects may be too costly even at $80/MWh power prices, given their high capital costs.

Key Challenges to Electricity Project Development

There are several policy, market, regulatory, technical and economic challenges inhibiting the development of new generation projects in Northern Alberta. Key challenges include:

- Regional transmission development is delayed, which will result in difficulties connecting generation projects to the grid in Northern Alberta;
- The current market structure does not allow renewable projects sufficient price certainty to acquire project investment and financing;
- The grid connection process, particularly for smaller projects, is too complex and onerous;
- There is not enough sun, and sometimes not enough wind or accessible hydro resources to develop certainty for renewable projects. Geothermal technology is not mature enough to warrant commercial investment at this time;
- There are difficulties with capital acquisition due to the risks associated with investment, both energy and carbon offset returns, and timing of connection for new generation projects; and
- There is an inability to capture value added benefits (such as location credits and carbon offsets) in Alberta.

Observations

The following electricity market recommendations may facilitate greater electricity project development activity in Northern Alberta and should be considered for immediate action:

1. Develop programs that recognize value adders such as location credits (for locating generation projects in areas of need) and carbon offsets (for clean, renewable generation projects);

2. Develop forward contracting market for intermediate-scale renewable generators. This may include the development of long-term power purchase arrangements that include energy and renewable offsets, as well as consideration for "bulk energy" products that would allow intermittent, renewable generators to sell a volume of electricity, irrespective of the time of day the electricity is produced. Natural gas generation and *demand response* could be used to "firm up" this intermittent generation; and

3. Streamline the regulatory process for micro-generation and intermediate-scale renewable project development, grid connection and operation. Currently there are no specific regulatory processes that target commercial generation projects less than 50 MW. As such, these projects get entangled in the lengthy processes with load and larger generation connections that can take as long as 3 to 3.5 years from initiation to connection.

Additional observations can be made with respect to opportunities and challenges to development in Northern Alberta including:

- The current regulatory and connection processes for industrial, commercial and institutional consumers who may be considering self-generation are lengthy and complex. This typically deters interest in self-generation projects;
- Generation options for large-scale integrated industrial projects are facilitated through Industrial System Designations (ISDs); however, the process is still lengthy and restrictive; and
- Self-generation options for larger commercial consumers, industrial consumers, institutions and municipalities need the development of application procedures and processes to review economic benefits in an efficient manner.

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1. Introduction

This report has been prepared by Forte Business Solutions Ltd. in response to a request for the development of a research paper on electricity options for Northern Alberta.

Based on various Northern Alberta Development Council (NADC) consultations, electrical power generation, renewable energy promotion and diversification of value-added technology have been identified as potential opportunities for Northern Alberta. As with most opportunities, there may be barriers that need to be identified and addressed for development to occur.

The primary objective of this research paper is to provide background information, to identify opportunities and to enumerate obstacles and solutions on the following electricity related issues:

- Northern power needs and options for supply;
- Conservation and energy efficiency opportunities and impacts;
- Power generation and distribution issues for local and regional systems;
- Northern power generation options and opportunities; costs and benefits; pros and cons;
- Access of small systems to the electric power transmission grid; and
- Recommendations for the NADC's consideration.

This research paper is divided into five main components, which address the current situation, options and opportunities, barriers and next steps. The Sections are outlined as follows:

1. **Current Alberta Electricity Environment**
    - An overview of the market, policy and regulatory environment for electricity and the key players;

2. **Current Northern Alberta Electricity Environment**
    - Specific details and special circumstances regarding the supply, demand, transmission and distribution situation for Northern Alberta;

3. **Options and Opportunities for Northern Alberta**
    - An overview of generation, conservation, carbon and other opportunities; and an evaluation of the alternatives;

4. **Barriers to Development**
    - Identification of policy, market, regulatory, technical and economic barriers;

5. **Next Steps**
    - Recommendations for overcoming barriers to development.

2. Current Alberta Electricity Environment

The Alberta electricity system is somewhat unique in North America due to:

- The "energy-only" nature of the hourly market;
    - Generators are paid for their output (electricity) on an hourly basis, instead of being paid government-backed "capacity payments" for being available to supply electricity – as in other jurisdictions. This "energy-only" nature puts generators at-risk to making all of their returns in the hourly market, or through forward contracts they are able to sell to market participants.
- The composition of the supply and demand structures;
- The unpredictability of high price events; and
- The split between de-regulated (market-based) generation and continued regulation of transmission and distribution.

Prior to determining opportunities for development, it is essential to understand the current Alberta electricity system. This chapter examines the role of the Alberta Electric System Operator ("AESO"), the various electricity markets in the province, the role of the Alberta Department of Energy ("Alberta Energy" or "DOE") and current government electricity policy respecting electricity transmission and distribution.

2.1 Electricity Markets

Electricity is measured in kilowatt-hours (kWh) or megawatt-hours (MWh). One MWh is equal to 1,000 kWh – which is approximately the amount of electricity a household uses on a monthly basis. Electric capacity (supply availability) and electricity demand are measured in kilowatts (kW) or megawatts (MW). This is an important differentiation. MW and kW are units of power. MWh and kWh are units of energy. Energy is the amount of work done, whereas power is the rate of doing work. One MWh is a million watts of power applied over the period of an hour.

Alberta has a central market for buying electricity (MWh) from generators on behalf of all provincial consumers. The Alberta Electric System Operator (AESO) operates this market. This section examines the role of the AESO, and provides an overview of the various and inter-related electricity markets in Alberta, including:

- The AESO Hourly Market;
- The Regulated Rate Option (RRO);
    - A pricing plan in effect for residential, farm and small commercial customers
- The Ancillary Services Market;
    - For the purchasing of system support services
- The Forward Power Market.

2.1.1 Role of the AESO

The Alberta Electric System Operator (AESO) is a not-for-profit entity, responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System (AIES). The AESO operates independent of any industry affiliations, is governed by an independent Board of Directors, and does not own transmission or market assets. AESO responsibilities include the following:

Responsibility Area	Description
Access to Grid	• The AESO provides *open* and *non-discriminatory* access to Alberta's interconnected power grid for generation and distribution companies and large industrial power consumers. • The AESO contracts with Transmission Facility Owners (TFOs) to acquire transmission services, and with other parties to provide system access. • The AESO is responsible for facility planning and produces short- and long-term plans for the development of the provincial grid.
Tariffs, Reliability and Settlement	• The AESO develops and administers *transmission tariffs* – required payments that customers must make in order to pay for the transmission system. • The AESO procures *ancillary services* to ensure system reliability. Ancillary services will be described further in Section 2.1.4. These are essentially support services that are purchased from generators and load customers (electricity consumers) to make sure the system stays operational in the event of generator outages and other contingency events. • The AESO manages *settlement* of the hourly wholesale market and transmission system services, including collecting revenue, paying costs and ensuring the dollars they take in matches the dollars they pay out.
"FEOC" Market Operation	• The AESO is responsible for ensuring a fair, efficient and openly competitive (FEOC) market for the exchange of electric energy in Alberta. • The AESO works to retain effective relationships with neighbouring jurisdictions. • The AESO works to ensure that Alberta's competitive electricity markets continue to operate in the best way possible, demonstrating that reliability is not compromised and that the structure is sustainable, predictable and adds long-term value. • The AESO operates the hourly market by taking generator offers and matching them against consumer bids and total electricity demand. The electricity in the hourly market goes through the AESO's clearinghouse and settlement process.

Provincial Load Settlement	• The AESO is accountable for the administration and regulation of the provincial load settlement function. "Load" is the term used to describe electricity consumers and the total electricity that they consume. Provincial load settlement involves matching the electricity volume that is consumed with the electricity volume that is produced by generators, and ensuring that electricity revenues match electricity costs.

Table 1: AESO Responsibilities

Overall, the wholesale electricity market, operated by the AESO, has over 200 participants and represents approximately $8 billion in annual energy transactions.

The AESO facilitates stakeholder feedback through a number of vehicles, including the Market Advisory Committee (MAC) – an entity that includes major generators and electricity consumers (loads), and meets on a monthly basis.

SECTION SUMMARY:

The Alberta Electric System Operator (AESO) is responsible for operating the electricity market and facility planning to ensure that electricity can be transmitted from where it is produced to where it is consumed. Any changes to market rules or customer connections to enhance Northern Alberta opportunities will be AESO concerns and will require their involvement.

2.1.2 AESO Hourly Market

Alberta has an "energy-only" market, where generators are paid for their output (electricity) on an hourly basis. Generators look to these price signals to determine whether to make investments in new generation projects.

Generators participate in the market by making hourly offers to supply energy. These offers are "stacked" in ascending order, starting from $0.00/MWh, to arrive at a cost to supply from all available generators. This stack is called the *"merit order"*. The AESO's system operators *"dispatch"* these generators based on the actual electricity consumption for every minute of the day. The term "dispatch" refers to an instruction from the system controller to increase or decrease the output of a generator to an agreed level. "Dispatch" typically refers to increases in output, and a "dispatch down" refers to decreases in output.

Industry participants generally refer to electricity consumption and the consumers who use electricity as *"load"*. In the merit order, the highest offer needed to meet the system demand, or load, establishes the price in that minute. These 60 minutes of prices (System Marginal Price or SMP) are then averaged over the hour to set the hourly price. All loads are charged the resulting price and all generators that are operating receive this price, unless they have made other contracting arrangements.

The system operators use a series of procedures to ensure that all load across the province is met in a reliable manner. This includes the use of operating reserves (to be discussed in Section 2.1.4) to compensate for short-term variations in demand and for the length of time it takes some generators to ramp up to their offered level of supply. Operating reserves are acquired from various generators and loads that can respond rapidly to dispatch instructions. The AESO acquires these supplies a day in advance of their usage, in a separate market, operated by the Natural Gas Exchange.

Most generators offer their units in one of three categories:

1. ***Zero dollar offers:***

   Generators that want to ensure that they will be dispatched every hour will offer at $0.00/MWh. This generally includes all units that need to run 24 hours a day such as coal units, co-generation units that produce steam for industrial use, and units that cannot respond to dispatch instructions such as wind generators.

2. ***Marginal cost offers:***

   Generators that want to ensure they recover their marginal costs to operate, such as natural gas units that need to cover their fuel and operating costs and coal units that are operating above their minimum operating levels.

3. ***Competitive offers:***

   Generators and importers that have a perception of the supply and demand fundamentals and are offering on a competitive basis. This group also includes some load customers that choose not to consume above certain price levels (referenced as price-sensitive loads).

For most hours in Alberta, it is the marginal cost offers that set the hourly prices with prices ranging from $10 to $12/MWh during overnight (off-peak) hours and $50 to $70/MWh during on-peak hours, generally dependent on the price of natural gas.

In a relatively few hours (about 15% of the time) the prices are determined by competitive offers. The prices can range from $75 to $1000/MWh based on the offer levels from competing generators and the level of demand. This last block is the end result of a competitive open market and it should be noted that generators are "at-risk" to their offers. If they are too high then their unit may not be dispatched and they earn no revenue. While these competitive hours make up only 15% of the time (about 1200 hours/year), they can account for as much as 50% of the total value of electricity over the year. As such, understanding the competitive dynamics during these hours is key to understanding the Alberta hourly market.

> **During the competitive hours, Alberta electricity prices are driven fundamentally by two uncertainty factors: wind availability and generation unit outages, predominantly coal outages. The result is that high price events are not coincident with high demand events as seen in Figure 1 below.**

The lack of a consistent and predictable relationship between prices and load is illustrated in Figure 1 below. The blue curve is the hourly load for each of the 8784 hours in 2008 sorted from smallest hour to highest hour in the year. The actual corresponding price for each hour is plotted in red and can vary from $0.00/MWh to $1000.00/MWh.

As is evident in the graph, the incidents of 'high prices' (prices greater than $100/MWh) are spread across almost all hours in the year, irrespective of the load level. The greatest frequency of high prices is between 40% and 70% of the load hours and not during the highest volume hours.

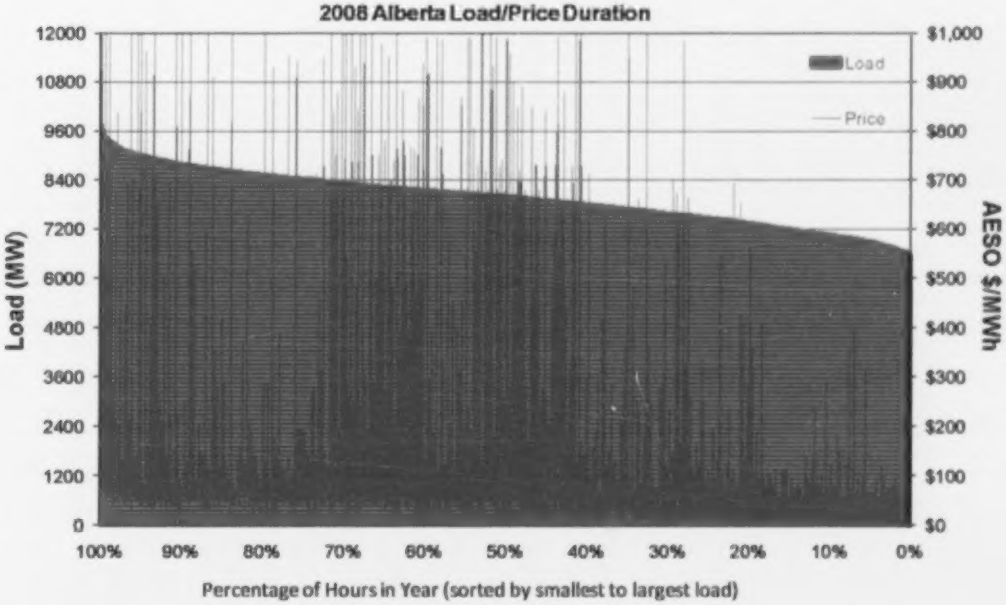


Figure 1: 2008 Load-Price Duration Curve

(Based on AESO Data)

The blue curve corresponds to the left hand axis and indicates the load level from a high of approximately 9,600 MW to a low of approximately 6,500 MW. The red line corresponds to the right hand axis and indicates the price in each hour associated with the demand level.

Similar graphs for 2007 and 2009 are included in Appendix 1. 2008 is shown because it was a year with a high incidence of prices in excess of $100/MWh, set by competitive offers. Conventional economics would suggest that the high price events should occur during periods of high demand. However, as is apparent from the 2008 curve, this is not the case in Alberta. High prices can occur in almost any hour of the year, and in 2008 these prices were evident over a broad range of hours. The market drivers for this phenomenon are discussed in more detail in the Demand Factors section that follows. The Market Surveillance Administrator (MSA) monitors these competitive offer events to ensure there is no collusion among market participants.

Understanding the nature of the AESO hourly market and its pricing dynamics is an important element to assessing generator alternatives in Northern Alberta. Large-scale investment opportunities, such as Slave River Hydro, Peace area nuclear, or oilsands co-generation are all affected by the pricing elements of this market, as are the economics of micro-generation, renewable and distributed energy projects and energy efficiency.

Supply Factors

Alberta has a total domestic power generation capacity of approximately 12,763 MW. Figure 2 illustrates the generation mix by fuel type.

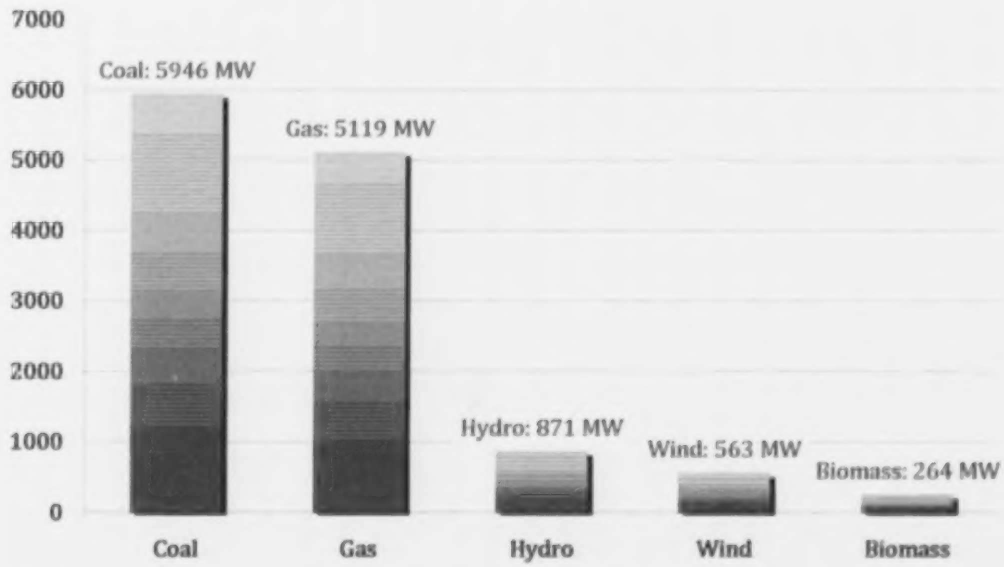


Figure 2: Alberta Generating Capacity

(Based on AESO Data)

Outside of domestic generation, there are 1,200 MW of interconnection capability on the B.C. intertie and 150 MW of interconnection capability on the Saskatchewan intertie. The B.C. intertie is currently constrained down to a maximum of 450 MW due to the lack of a system support service in Alberta referred to as *Load Shed Service for Imports* (see Section 2.1.4). In total, Alberta can currently support 600 MW of imports; however, Alberta Energy and the AESO have made increasing the intertie capacity a key priority for 2010.

Recently, Alberta's generation fleet has transitioned from a predominantly coal-based structure, to a system with more natural gas-fired generation. The coal-based system was supported by transmission and distribution infrastructure moving energy from the fuel source to consumers. The current structure has more generation located closer to the points of consumption. We now have a series of natural gas-fired co-generation and combined cycle facilities. The coal fleet is aging and will not meet future emissions standards without major capital investment.

New generation investment in Alberta is primarily in gas units, for co-generation or system support, and wind generation. In terms of proposed generation development projects, as of February 2010 there are 82 projects, totaling 13,226 MW, seeking approvals distributed as set out in Figure 3.

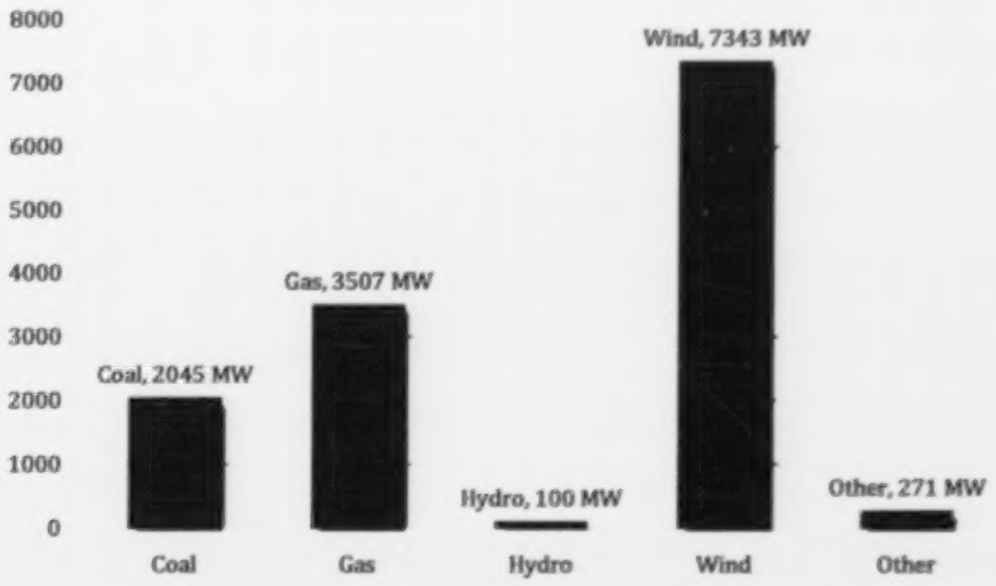


Figure 3: Generation additions in AESO Connection Queue as at February 2010

(Based on AESO Data)

The existing and future investments in wind projects tend to de-stabilize both the hourly energy prices and the reliability of energy supply. This is because wind power is intermittent and has priority access to the system. The end result is that more zero dollar offers come on to the system, drive the price down, and require more system support because of the unpredictable nature of wind.

Future baseload supply may be dependent on carbon capture and storage (CCS) supplementing coal units, distant northern hydro, controversial nuclear or integrated gas co-generation with oilsands development.

Demand Factors

Alberta's peak demand was 10,236 MW in December 2009, up from 9,806 MW in 2008. Alberta's load is dominated by industrial consumption, as illustrated in Figure 4, at approximately 60% market share (by volume of electricity consumed) in 2008. This is 25% greater than most electricity markets.

> **Industrial load tends to be less variable (more "flat") in volume, which has led to Alberta having one of the highest load utilization factors of any North American power jurisdiction at just over 80%.**

This high incidence of baseload coupled with a relatively low peak-to-average demand has resulted in little action to develop effective demand response to use as a reliability tool during peak periods. Unlike other jurisdictions, there is little flexibility to cut consumption without damaging the economy. It should be noted that a significant component of the industrial load is supported with co-generation supply.

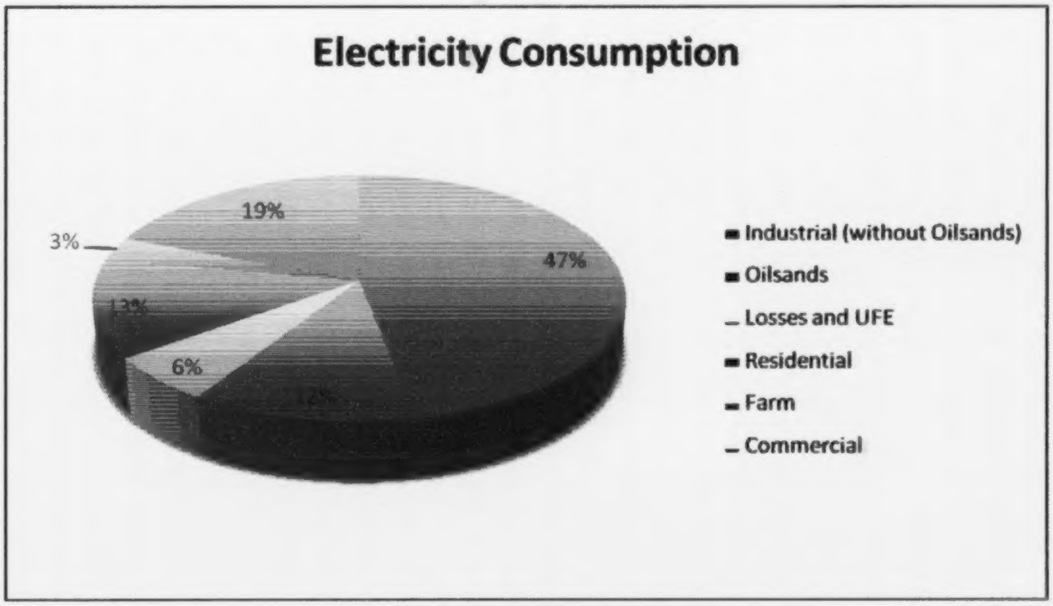


Figure 4: Alberta Electricity Consumption

(Based on AESO Data)

In comparison to other regions, Alberta consumers are not prime candidates for price-driven demand response programs due to the unpredictability of the AESO hourly price signal. Appendix 1 includes a detailed analysis that illustrates the behaviour of the hourly prices in 2008 and 2009. This analysis indicates that high prices are not predictable on a seasonal, day-of-week, hourly, or demand level basis. Essentially, price levels respond to uncertain events, weather impact on loads, wind generation and un-scheduled generator outages.

The AESO hourly market was developed in 1995 as a mechanism to dispatch large-scale baseload generators, such as the coal facilities west of Edmonton. The hourly prices resulting from this mechanism have experienced added volatility as a result of new natural gas and wind generation that has been constructed over the past ten years. The result is that the current price signals are relatively ineffective in their ability:

- To incent energy efficiency and demand response among consumers;
- To provide effective incentives for investments in renewable and alternate fuels; and
- To recognize the value of regional based generation projects.

SECTION SUMMARY:

The AESO hourly market has evolved as a dispatch tool for large-scale baseload generators and is not efficient in its ability to incent energy efficiency and demand response among consumers. The price signals do not provide effective incentives for investments in renewable and alternate fuels. There is no price signal to encourage generation to be located in specific areas of the province. These issues will be discussed in subsequent sections of this report.

2.1.3 Regulated Rate Option and Retail Contracts

Alberta residential, small commercial and farm customers who consume less than 250,000 kWh annually and do not sign retail contracts for electricity are deemed to be on the Regulated Rate Option (RRO) and are served by a Regulated Rate provider. There is one Regulated Rate provider for each distribution franchise area of the province, and the rates are set each month and subsequently reviewed and approved by an Independent Advisor and the Alberta Utilities Commission (AUC).

Regulated Rate providers include:

- EPCOR Energy Alberta Inc. in the FortisAlberta service territory;
- Direct Energy Regulated Services in the ATCO service territory;
- ENMAX Power Corp. for the city of Calgary;
- EPCOR Energy Alberta Inc. for the city of Edmonton;
- Other municipally owned utilities, including the City of Lethbridge; and
- Rural Electrification Associations (REAs).

Regulated Rates are established by Energy Price Setting Programs (EPSPs) that are based on forward energy prices. Forward energy prices are actual agreements between parties to buy or sell electricity at a certain future time for a certain price agreed today. The pricing for the EPSPs is based on a combination of longer-term contracts (greater than one year) and shorter-term products that are procured a month in advance of real-time. The ratio of shorter- and longer-term products is specified in Regulation, outlined as follows:

Timeframe	% Longer-term Pricing	% Shorter-term (month-in-advance) Pricing
July 2009 to June 2010	20 %	80 %
July 2010 to June 2011	0 %	100 %

Table 2: RRO Pricing

Consumers on Regulated Rates do not pay the wholesale energy price, as established by the AESO Hourly market – a concept known as *"flow-through pricing."*

In order to achieve effective energy efficiency or energy conservation through Advanced Metering Infrastructure (AMI or "smart meter") programs, it is essential that the price the consumer sees be close to the actual price of energy at time of consumption. Currently, the Regulated Rates in Alberta reflect the price of energy in the month in advance of consumption and would require changes to regulations to reflect short-term hourly price changes.

Many North American jurisdictions that are implementing smart grid programs use time-of-use (TOU) pricing to reflect the time-varying cost of electricity. This mechanism sets prices for different times of the day to encourage shifting of energy use from high price to low price times, and to encourage more efficient use of energy. Alberta Energy is not contemplating the use of TOU rates in concert with its AMI program.

Approximately 70% to 75% of all Alberta electricity consumers are expected to remain on the RRO program through to July 2011, instead of switching to *retail contracts* (forward contracts

with electricity retailers). The absence of hourly price signals for residential, small commercial and farm customers may inhibit the effectiveness of the government's AMI program.

In July 2011, there will either be a new RRO program or an extension of the current program, likely using 100% month-in-advance pricing. *Flow-through pricing* will not likely be used in Alberta because it is too problematic to result in any effective price signals for meaningful energy efficiency or conservation.

Retail Contracts

Instead of paying Regulated Rates, residential, small commercial and farm customers can elect to sign with a retailer and receive a retail rate for electricity. Alberta retailers generally purchase wholesale electricity or generate their own electricity, and then sell this electricity to retail consumers to cover their contracted positions. Alberta electricity retailers include:

- Direct Energy;
- ENMAX Energy Corp. (EasyMAX);
- Just Energy Alberta LP;
- Spot Power Company Inc.

Some large industrial customers act as self-retailers in the electricity market.

SECTION SUMMARY:

Alberta residential, small commercial and farm customers, who have not signed retail electricity contracts, fall under the Regulated Rate Option (RRO). The RRO program specifies how suppliers provide electricity rates to small consumers through a combination of month-ahead purchases and risk margins for variability in actual consumption. Currently, the Alberta Energy Advanced Metering Infrastructure (AMI) initiative does not contemplate any special rate incentives to encourage energy efficiency from RRO consumers.

At the current time, there are no retailers specializing in energy efficiency programs that use price as an economic driver to conservation. The implications for Northern Alberta echo those of the rest of the province in that achieving energy efficiency from farm, residential and small commercial consumers will require local programs that are based on economic drivers and incentives other than energy pricing to be successful.

2.1.4 Ancillary Services Market

Ancillary services (AS) are required to ensure that electricity can be transmitted reliably, efficiently, and securely across Alberta's interconnected transmission system. Because electricity is not easily stored, and supply must instantaneously meet demand levels, operating reserves are used by the system controller to ensure this supply-demand balance is met. When there is an unexpected imbalance between supply and demand due to the failure of a generator or transmission line, operating reserves are dispatched to maintain the supply/demand balance.

The AESO is mandated through the Alberta Electric Utilities Act to procure ancillary services as determined by reliability standards set by the Western Electricity Coordinating Council (WECC), an electricity area stretching from B.C. and Alberta in the north to California in the south. Table 3 below, provides a summary of the Alberta market for operating reserve products. The AESO procures both active and standby operating reserve products. Active reserves are procured to meet the requirements of the Alberta Integrated Electrical System (AIES) under normal operating conditions. Standby reserves are procured to provide additional reserves for use when the active reserves are insufficient or have already been dispatched.

Product	Description	Types of Products
Regulating Reserve	• Automatic Generation Control (AGC) capable of providing sufficient regulating margin to allow the control area to meet WECC Control Performance Criteria.	• Active Regulating Reserve; • Stand-by Regulating .
Contingency Reserves	• Spinning Reserves: o Provided by Generation Resources already synchronized to the grid who are capable of increasing their generation output within 10 minutes. • Supplemental (Non-Spinning) Reserves: o Provided by Generation Resources already synchronized or not currently synchronized to the grid, but which can be ramped up to offered capacity within 10 minutes, or Demand Responsive Resources capable of reducing their energy usage within 10 minutes.	• Active Contingency Reserves; • Stand-by Contingency Reserves.

Table 3: Operating Reserve Products

Operating reserves are acquired by the AESO from generators and dispatchable loads (those who can turn on and off in short notice) a day in advance of usage. The pricing of these reserves is through a competitive process in a market operated by the Natural Gas Exchange (NGX). These reserves are procured from across the province to ensure all areas can be reliably supported. This does provide some unique opportunities for both generators and loads in Northern Alberta.

Operating reserves are generally transacted as an index to the pool price, making the total ancillary services (AS) costs a function of the AESO hourly price. Other ancillary services are procured by the AESO using bilateral contracts. These services are outlined in Table 4.

Service	Description
Transmission Must Run	• TMR is generation required to be online and operating at specific levels in particular parts of the AIES; • The AESO contracts with regional generators for TMR to compensate for insufficient local transmission infrastructure relative to local demand.
Black Start Services	• The AESO procures black start service from generators (in specific areas) that are able to restart their generation facility with no outside source of power; • In the event of a system-wide blackout, black start providers are called upon to re-energize the transmission system and provide start-up power to generators that cannot self-start.
Load Shed Services (LSS)	• The AESO contracts with large electrical consumers to be able to automatically trip off their power supply in order to instantly reduce demand when an unexpected system event occurs.

Table 4: Other Ancillary Service Products

The AESO's forecast for AS costs for 2010 is $152 Million. These costs are included in the AESO tariff and are paid for by electricity consumers. Figure 5 illustrates the breakdown of AS costs for 2010.

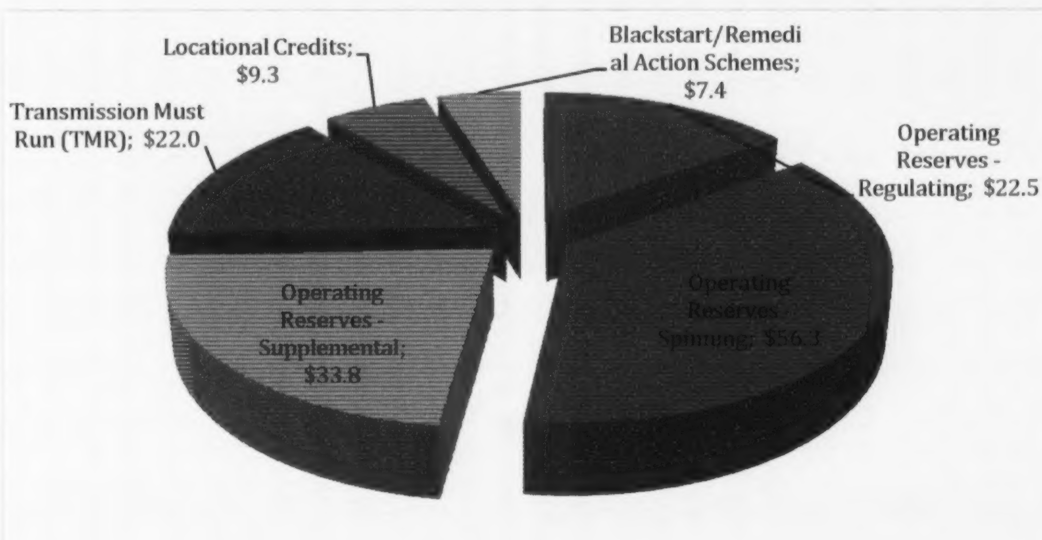


Figure 5: Ancillary Services budgeted costs for 2010, by category ($ Million)

The AESO is currently facilitating an Operating Reserve Market Re-design process. A discussion paper on the re-design was published last year, and a recommendation paper was published on March 25, 2010.

Parts of Northern Alberta are transmission-constrained areas. This makes the opportunities to provide ancillary services an important element in generation project economics. For example, the most recent natural gas facility built by Constellation Energy in the Grande Prairie area targets both the ancillary services and energy markets.

TMR payments occur in two components: fixed and variable. Fixed payments are made for being available, whereas, variable payments are acquired for operating when required. When new transmission is built in a TMR area, TMR variable payments are reduced. TMR fixed payments continue until the contract term expires.

As the load growth occurs in the North, the need for more northern-based AS will increase. Other than operating reserves, ancillary services are competitively bid, longer-term contracts with the AESO. The OR markets are daily markets, also bid competitively and transacted as discounts to the energy price. Profitability is dependent upon load growth, AESO hourly price and competition between suppliers. Suppliers will need to develop strategies to market the ancillary services at prices greater than fixed costs. The opportunities for Northern Alberta relate to both the regional-specific products (such as TMR) and the overall market products.

SECTION SUMMARY:

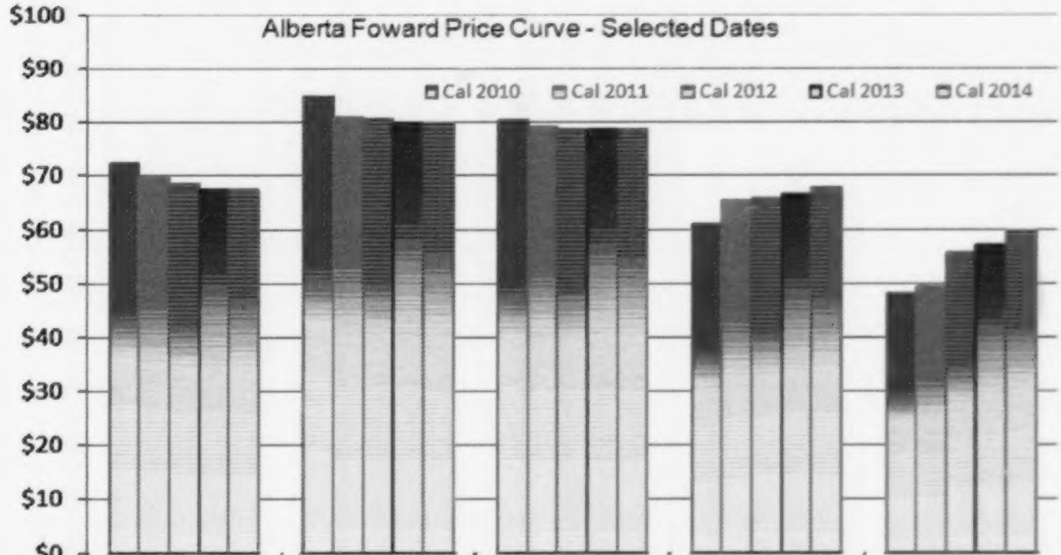
Ancillary services are required to support the electricity grid and ensure that electricity can be transmitted reliably, efficiently and securely. The system controller uses ancillary services to ensure that electricity supply instantaneously meets electricity demand. Sections of the Northern Alberta transmission system need additional ancillary services to support them. Providing ancillary services as a part of energy projects is an opportunity for Northern Alberta. Profitability for ancillary service suppliers will be dependent upon load growth, AESO hourly price and competition between suppliers.

2.1.5 Forward Markets

Forward markets provide important indicators of prices in the future and become a guide to investors making decisions on timing and fuel-sources for future generation projects. Investors in oil, natural gas and bitumen recovery all look to forward markets for signals as to timing for future investments. Low forward prices will result in the deferring and cancelling of projects, while high prices signal the need for new investments. This is also the case for electricity generation projects in Alberta; however, the clarity of these forward prices is not as good as for other energy products.

Forward prices can change dramatically over a relatively short time, as seen in Figure 6. The 5-year curve went from $68/MWh in January 2008 up to $80/MWh by January 2009 and back to $55/MWh by January 2010. These forward curve variations add significant risks to new investments that rely solely on energy prices. At $80/MWh price levels, an entire range of generation options can be considered including coal with some form of carbon capture, wind and other renewable, and a suite of co-generation and natural gas combined cycle facilities.

At the current $55/MWh forward prices, almost all of these options are precluded, the exception being co-generation plants that utilize the low natural gas prices and have alternate revenue compensation from steam production. The generation options will be examined further in Section 4.5.



	Jan 01 08	Jul 01 08	Jan 01 09	Jul 01 09	Dec 31 09
Cal 2010	$72.50	$84.75	$80.50	$61.00	$48.00
Cal 2011	$70.00	$81.00	$79.25	$65.25	$49.30
Cal 2012	$68.50	$80.75	$78.75	$65.75	$55.75
Cal 2013	$67.50	$80.00	$78.75	$66.50	$57.00
Cal 2014	$67.50	$80.00	$78.75	$67.75	$59.75

Figure 6: Alberta Forward Curve 2008 to 2010

Note: 'Cal' - designates a calendar year product from January to December

SECTION SUMMARY:

The forward price curve in Alberta is a key driver for energy opportunities in Northern Alberta. The current low forward price signals in the market suggest that many projects will be deferred until prices rise. However, other factors affect supply demand balances in Northern Alberta that are unique from those of the province as a whole.

Subsequent sections of this report identify the transmission constraints and load growth expectations that may provide new generation investment opportunities.

The structure of the power market in Alberta does not allow for regional differences to be reflected in prices, as we rely on uniform rates for transmission and single hourly prices for the entire province.

2.2 Government Policy

Alberta Energy is responsible for setting overall energy and electricity policy and establishing the corresponding legislation.

From an overall policy perspective, it is important to consider the Alberta Government's Provincial Energy Strategy (PES), released in December 2008. The overall vision of the PES is that *"Alberta will remain a global energy leader, recognized as a responsible world-class energy supplier; an energy technology champion; a sophisticated energy consumer; and a solid global environmental citizen."* The PES outlines a range of programs to enhance electricity's role as "a facilitator of economic development in Alberta" including:

No.	Action
1	Develop a plan for transmission improvements
2	Implement a transmission build policy to renewable/ low-emission generation sources
3	Implement an intertie build policy to other markets
4	Streamline regulatory process for transmission siting
5	Assemble multi-use corridors for energy and transportation infrastructure
6	Undertake an education and awareness program
7	Implement policy and provide financial support for "smart grid" technology

Table 5: Provincial Energy Strategy

Policy action items 1, 2 and 7 are particularly relevant to Northern Alberta and to the objectives of the NADC project. On the supply side, in addition to various major transmission upgrades, the government intends to build transmission to support environmentally friendly resources. On the demand side, the government is promoting Advanced Metering Infrastructure (AMI or "smart grid" technology) to facilitate customer engagement in energy efficiency.

With respect to transmission policy, the government moved forward during 2009 with a series of new projects and a new project approval process. The Electric Statutes Amendment Act (formerly Bill 50) is intended to expedite the development of transmission lines in Alberta by designating certain new facilities as Critical Transmission Infrastructure (CTI) and expediting their approval process. The basis for the Bill was established in the Provincial Energy Strategy, and the Act received Royal Assent on November 26th, 2009.

The Electric Statutes Amendment (ESA) Act, 2009, amends the following three Acts:

1. The Alberta Utilities Commission Act;
2. The Electric Utilities Act; and
3. The Hydro and Electric Energy Act.

Key aspects of the ESA Act are outlined as follows:

- The Government of Alberta has the responsibility for identifying which transmission infrastructure is needed, the AUC process will determine siting based on safety, reliability and environmental factors;
- Electric Utilities Act amendments include authorizing the need for the first group of Critical Transmission Infrastructure (CTI) projects and establishing a legislative approval process for future projects;
- CTI Projects include the following transmission lines (illustrated in Figure 7):
    - Edmonton to Calgary: two High Voltage Direct Current (HVDC) lines that will carry more power to customers in central and southern Alberta;
    - Edmonton to the Heartland region: a 500 kV Alternating Current (AC) line to address the power needs of industry;
    - Edmonton/Heartland region to Fort McMurray: two 500 kV AC lines to support ongoing oil sands development and enable the connection of industrial cogeneration into the provincial transmission system (to be staged based on AESO established milestones); and
    - Calgary reinforcement: an upgrade of the system in and around the City of Calgary. The upgrade is required to carry additional electricity and provide stronger connections and power service to the city and nearby towns.
- The Southern Alberta Transmission Reinforcement [two double circuit 240 kV lines along with a new 500 kV substation to increase the ability of the southern system to connect new wind farms] is already approved by the AUC and is to be developed in stages based on eclipsing AESO established milestones.

The total transmission increase from the 2010 cost base is $9.5B. This is assuming that these projects are constructed for their respective projected costs. Based on the AESO forecasted load growth to 2017, the new transmission will add $12.10/MWh to consumer bills.

Figure 7: Map of Critical Transmission Infrastructure

With regards to the "smart grid" objective, Alberta Energy has released two papers on AMI. The first was a discussion paper, published on May 26, 2008, and entitled: "New Energy Efficiency Opportunities for Albertans Through Advances in Metering". After some project delays, Alberta Energy released the follow-up paper "Straw Model – Advanced Metering Infrastructure" on January 21, 2010.

AMI is a relatively new term that refers to networks or systems that measure, collect and analyze electricity consumption from advanced devices through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications, customer associated systems and meter data management software.

The meters are often referred to as "advanced electric meters" or "smart meters", since they often can use collected data based on programmed logic. AMI is viewed as an enabling technology for distributed generation, micro-generation, and other distribution-connected energy supply.

Stakeholders recently compiled and submitted feedback to this Straw Model. Alberta Energy will be issuing a policy paper in April 2010 and is targeting the end of 2010 for new AMI regulations The AMI and overall "smart grid" concepts will be expanded upon in Section 4.2.1 and Appendix 3.

Alberta Energy also has specific policy initiatives with respect to renewables and alternate fuels and with respect to energy efficiency that should have direct implications for electricity development in Northern Alberta. As these programs are developed over 2010, it will be important to enumerate any regulatory, market and policy concerns that may exist to impede implementation. These barriers and potential solutions are identified in Sections 5 and 6 of this report.

SECTION SUMMARY:

Alberta Energy released its Provincial Energy Strategy in December 2008, and has been working on a series of objectives including:

- Developing several key electricity transmission projects, some of which will enable renewable and low-emissions energy projects to connect to the grid; and
- Outlining an implementation plan for "smart grid" technology in order to facilitate conservation and energy efficiency.

2.3 Electricity Transmission

Electricity transmission consists of a system of high-voltage power lines and other electrical equipment that moves power from generators to large load centers, such as cities and industrial areas. Once electricity is generated, a step-up transformer is used to adjust to a higher, transmission-level voltage, and the electricity is transmitted towards the consumption area. At this point it is either "stepped down" (transformed to a lower voltage) to an industrial site, or to a distribution system where it is distributed to the end user. Electricity transmission is a *natural monopoly* situation where one entity owns and operates an area of the system, without competition from other electricity transmission networks. Electricity transmission networks are extremely expensive to build, and as a result, there is generally a single transmission supplier in each area. Transmission Facility Owners (TFOs) own, operate, build and maintain the system in specific Alberta franchise areas.

In Alberta, power lines with voltages under 25 kV are generally considered distribution, and anything above that is considered transmission; however, this does vary depending on the TFO franchise area.

Transmission tends to be built in large increments and has a long service life (40 to 60 years). Ideally, new transmission facilities should be built in anticipation of need. The permitting and construction timeframes for transmission facilities are quite long and as such, they may not be built in time to respond to a particular identified need. For example, it can take between 18 months and three years to plan, acquire approvals and build some types of generation, including natural gas and wind, while it can take five-to-eight years to plan, acquire approvals and build new major transmission infrastructure.

There are around 21,000 kilometres (km) of transmission lines in Alberta. The bulk transmission system includes 240 kilovolt (kV) and 500 kV transmission lines and components, and the regional transmission system includes transmission lines and components at voltages of 240 kV or lower that are located in six geographic regions in Alberta (further discussed in Chapter 3).

There are four major TFOs in Alberta, described briefly below:

ALTALINK

AltaLink, a Limited Partnership between SNC-Lavalin Energy and Macquarie Essential Assets Partnership, owns and operates 11,800 km of transmission lines and approximately 270 substations in Alberta. AltaLink transmission lines range from 69 kV to 500 kV and serve approximately 85 per cent of Alberta's population. AltaLink also owns the Alberta portion of the interconnection to British Columbia used to import and export electricity, connecting Alberta to the power grid in the Pacific Northwest.

ATCO ELECTRIC

ATCO Electric owns and operates a system of transmission lines and distribution lines in Alberta, including 9,300 km of transmission line and 58,000 km of distribution line (further discussed in Section 2.4). ATCO Electric also operates isolated generating units in remote communities.

Figure 8 illustrates a map of ATCO Electric service territory with its significant impact on Northern Alberta.

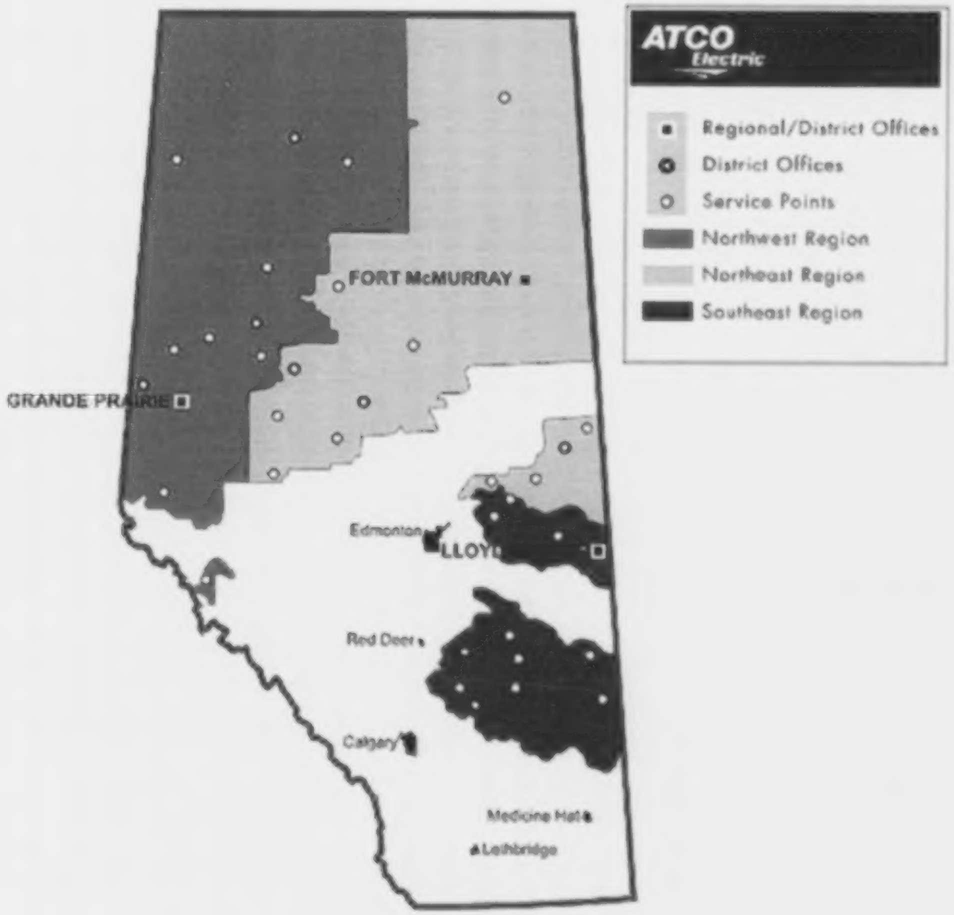


Figure 8: ATCO Electric Service Territory

ENMAX and EPCOR

Table 6 provides an overview of the electricity transmission roles played by ENMAX and EPCOR:

Entity	ENMAX Power Corp.	EPCOR Energy Inc.
Owner	City of Calgary	City of Edmonton
Franchise area	Calgary Area	Edmonton Area
Transmission lines owned and operated	281 km	203 km

Table 6: ENMAX and EPCOR Transmission Overview

SECTION SUMMARY:

The electricity transmission system is composed of high-voltage power lines and related equipment that move electricity from the generators that produce the electricity to the end users who consume the electricity. There are four major transmission facility owners in Alberta: AltaLink, ATCO Electric, ENMAX and EPCOR.

2.4 Electricity Distribution

Once electricity has been produced at a generating station, it is generally transformed or "stepped up" to transmission (high) voltage, via a transformer, and transmitted along the bulk system, as illustrated in Figure 9. It is then transformed or "stepped down", by transformer, to a distribution (lower) voltage and distributed to an end user. Distribution voltage is typically anything less than or equal to 25 kV in Alberta. A Distribution System is made up of lower voltage power lines and sub-stations.

Figure 9: Electricity Generation and Transportation

(Source: Alberta Utilities Consumer Advocate)

Electricity distribution (wire service) providers are responsible for:

- Performing 24-hour outage repair and emergency response;
- Building, maintaining, and upgrading power lines and facilities;
- Installing and reading electricity meters;
- Providing load settlement services;
- Providing consumption data to retailers, who in turn bill customers; and
- Promoting electrical safety education.

Electricity distribution, like transmission, is a monopoly business and Distribution Facility Owners (DFOs) are wire service providers with specific franchise territory. Four main DFOs, Rural Electrification Associations (REAs) and municipal owned utilities provide distribution service in Alberta. This section briefly describes the various distribution service providers.

ATCO Electric

ATCO Electric, part of the ATCO Group of Companies, owns and operates a distribution system consisting of over 58,000 km of line. They also operate 12,100 km of line owned by REAs. ATCO Electric serves over 202,000 customers in 245 communities in Northern and East-central Alberta. The ATCO Electric service territory map was provided in Section 2.3, Figure 8.

FortisAlberta

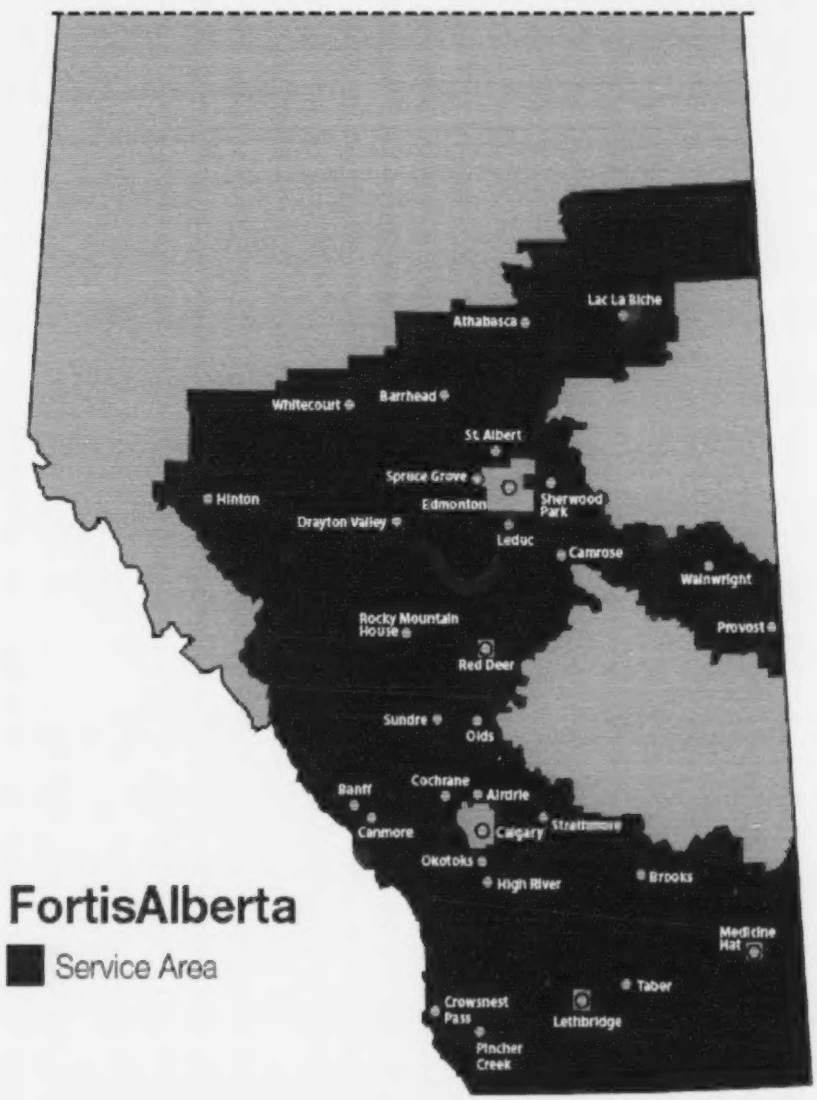


Figure 10: FortisAlberta Service Area

FortisAlberta, a wholly owned subsidiary of Fortis Inc., owns and operates 108,400 kilometres of power lines, providing close to 60 per cent of Alberta's distribution system. FortisAlberta serves over 463,000 customers in 175 communities in southern and central Alberta.

FortisAlberta's service territory is highlighted in Figure 10 with attention drawn to its impact in the Northeast region of Alberta.

ENMAX

ENMAX Power Corporation, a wholly owned subsidiary of the City of Calgary, owns and operates over 7,383 km of distribution lines and delivers approximately 8,990 gigawatt-hours of electricity annually (based on 2008 data).

EPCOR

EPCOR Distribution & Transmission Inc. (EDTI), a subsidiary of EPCOR Utilities Inc., distributes approximately 14% of the province's electrical energy consumption to over 300,000 residential and commercial customers in the Edmonton area.

Rural Electrification Associations (REAs)

An REA is a not-for-profit cooperative, incorporated under the Rural Utilities Act, which owns an electric distribution system and supplies electric energy to members in a rural region of Alberta. There are around 44 REAs and 43,000 REA Members in Alberta. REAs fall into two categories, as follows:

1. Self-Operating REAs
   - REA owns and operates their wires service.
2. Operating REAs
   - REAs serviced by Distribution Facility Operators (DFOs). The REA generally owns the wires, and the DFO operates the wires service.

There are a limited number of REAs in Northern Alberta, primarily in the Peace River area. Through affiliates, REAs may provide opportunities for small-scale, farm-based electricity generation projects.

SECTION SUMMARY:

The electricity distribution system is composed of lower-voltage power lines and related equipment that move electricity from the bulk transmission system to the end users who consume the electricity. There are four major distribution facility owners in Alberta: ATCO, FortisAlberta, Electric, ENMAX and EPCOR. Rural Electrification Associations (REAs) also distribute electricity.

2.5 Industrial System Designations

An Industrial System Designation (ISD) is effectively an exemption from the Electric Utilities Act, eliminating the requirement to exchange energy through the AESO market. ISDs have become particularly relevant in Northern Alberta in recent years with more oilsands development in the Athabasca, Peace River and Cold Lake regions, as illustrated in Figure 11.

The need for steam, the benefits of co-generation and the time restrictions involved in building sufficient transmission to oilsands projects have led companies to build their own supply on site. Hence, an ISD becomes an attractive engineering and financial decision for these projects.

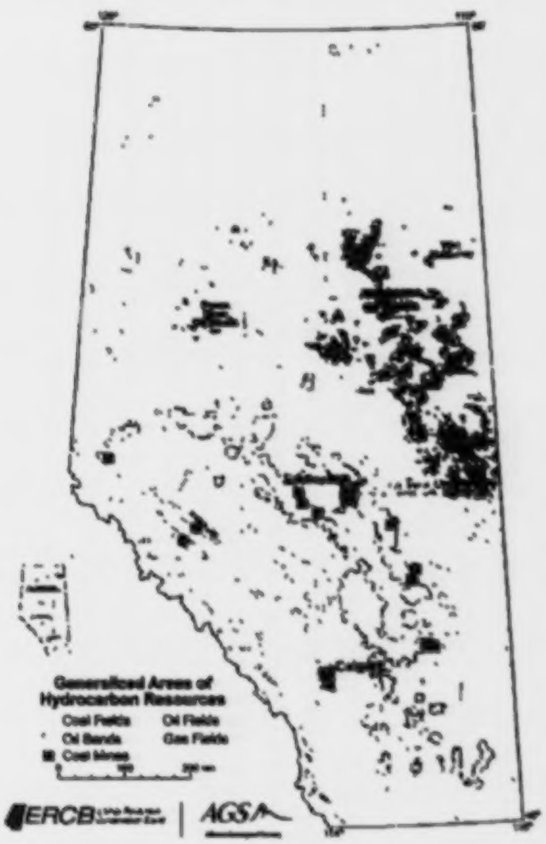


Figure 11: Alberta Hydrocarbon resources

An ISD is unique to Alberta, and allows the ISD approval holder to:

- Produce, transmit and consume electrical energy for its integrated industrial processes; and
- Interconnect with the Alberta Interconnected Electric System (AIES) to facilitate site import/export transactions.

In order to meet the ISD approval requirements, a proponent must:

- Demonstrate a significant investment in generation that is integral to the industrial process;
- Demonstrate a high degree of process integration (manufacturing, ownership);
- Demonstrate the facility costs are equal to or less than the tariff (if off lease facilities are proposed); and
- Demonstrate that the ISD satisfies an "economic & orderly" *development planning* test.

An ISD is defined by the facilities (Generation, Transmission & Distribution) and any unique terms and conditions in the ISD Order.

The development of the oilsands has been one of the main drivers of electrical energy project construction. Going forward, ISD development will affect the balance of electricity supply and demand in Northern Alberta.

SECTION SUMMARY:

Industrial System Designations (ISDs) allow entities with integrated processes to avoid exchanging all electricity through the AESO market, and save time and money as a result. Oilsands developments, which need steam and electricity, are the main type of ISD project. ISDs will likely play a large role in Northern Alberta electricity development.

One of the critical decisions in oilsands development and use of ISDs is whether the generation capacity is limited to the requirements of the project or is expanded to provide net additional capacity for sale into the power market. This decision point is influenced by the thermal steam load required; however, is also guided by the forward price curve, the availability of transmission to other areas, and the complexity of operating a commercial generation facility.

3. Current Northern Alberta Electricity Environment

Northern Alberta is a tale of two contrasting regions. The Northeast has, and will continue to experience, high growth from industrial electricity demand, primarily oilsands development supported by co-generation projects. The Northwest is also expected to sustain growth, but to a lesser degree, while experiencing some transmission constraints and voltage support issues (to be examined in Section 3.2.3).

The following two Figures, from the AESO's 2009 Seasonal Reliability Outlook, illustrate regional divisions as well as the winter and summer Peak for Alberta Internal Load and the expected growth over the next twenty years.

Based on the AESO's projections the Northeast region will have the largest growth in winter peak requirements to 2029 growing by 150% from 2,063 MW to 5,140 MW. By contrast, the Northwest area is projected to grow from a winter peak of 1,058 MW to 1,852 MW or a 75% increase between 2009 and 2029.

It will be interesting to see the sources of generation that will evolve to meet this growth in consumption over the next twenty years. Winter and summer electricity demand peaks for all Alberta regions are illustrated in Figures 12 and 13.

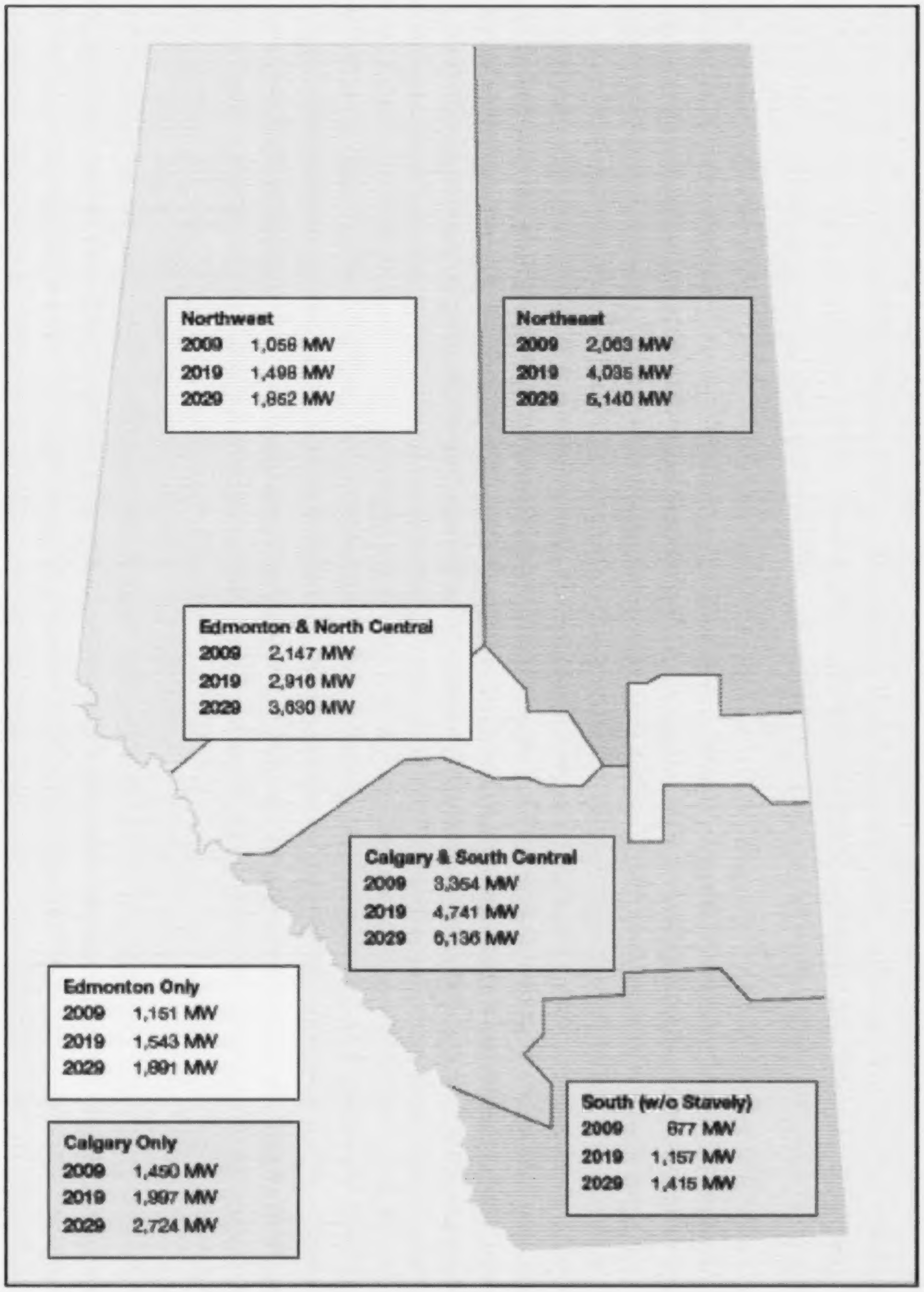


Figure 12: Regional Demand at Winter Peak (Alberta Internal Load)

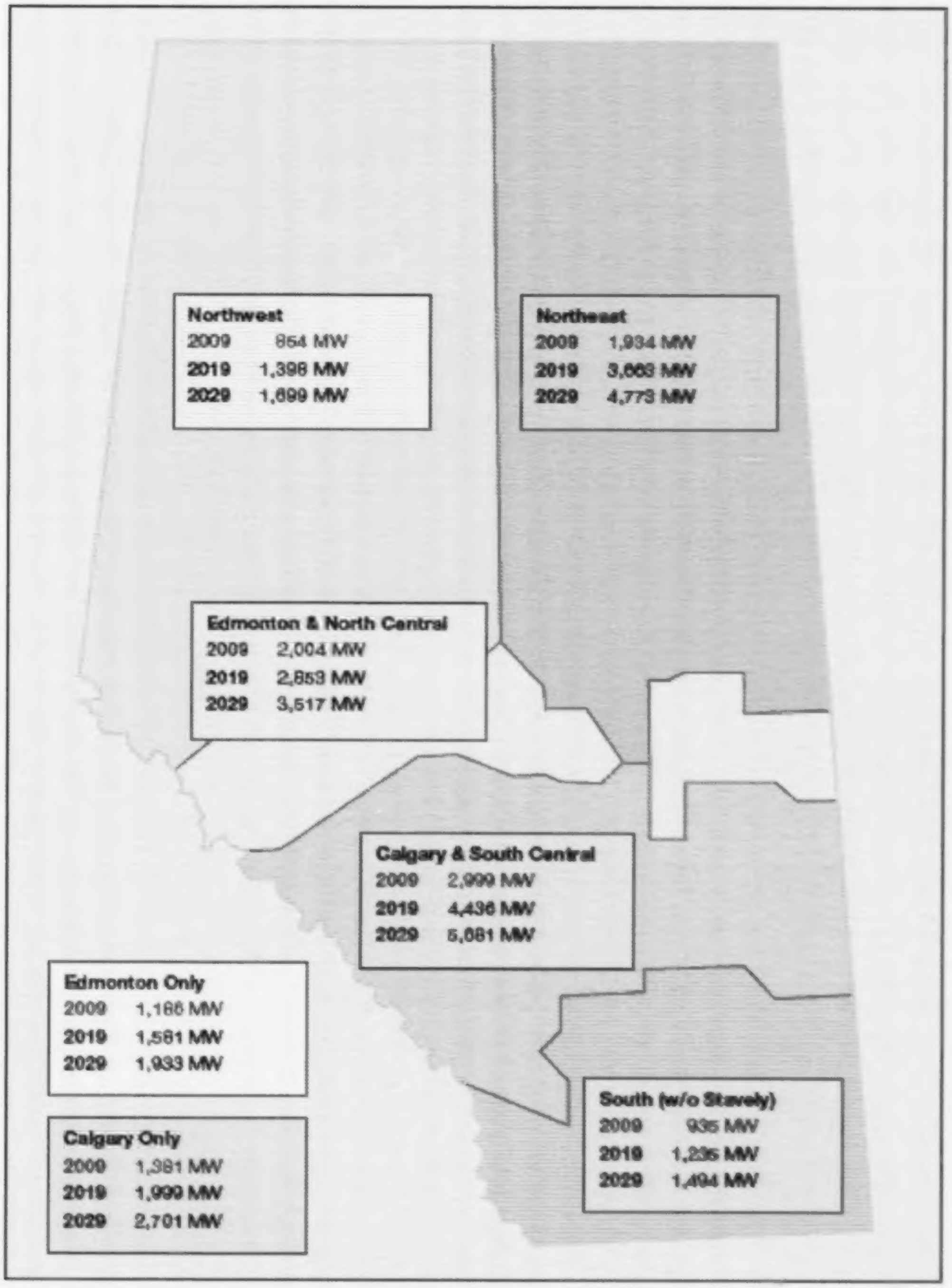


Figure 13: Regional Demand at Summer Peak (Alberta Internal Load)

Source: 2009 Forecast undertaken by the AESO – released March, 2010

3.1 Northeast Region

The Northeast region of Alberta includes Fort McMurray, Athabasca/Lac La Biche and Cold Lake. Region boundaries, as denoted for the purposes of AESO planning are outlined in Table 7 below:

Direction	Boundary
North	Northwest Territories Border
East	Saskatchewan Border
West	Fifth Meridian
South	Township 60

Table 7: Northeast Region Boundaries

3.1.1 Northeast Supply

Generation in the Northeast region is entirely natural gas-fired, including the generators listed in Table 8:

Generator	Capacity
Foster Creek	80 MW
Mahkeses	180 MW
Muskeg	202 MW
McKay River	165 MW
Syncrude	510 MW
Suncor Millenium	525 MW
Nexen Opti	180 MW
MEG Energy Christina Lake	94 MW
CNRL Horizon	103 MW
Primrose	85 MW

Table 8: Generators in the Northeast

Northeast generation accounts for approximately 18 percent or 2,440 MW of Alberta's 12,763 MW of total installed generation capacity.

3.1.2 Northeast Demand

According to AESO forecasts, the Northeast region is expected to experience the greatest load growth over the next 10 years. This is predominantly due to the oilsands and forestry industries and secondary service industries in the municipalities created by the *multiplier effect*.

Northeast load is mostly industrial and constitutes approximately 1,800 MW or 18 % of the provincial peak load. The majority of the load and generation is located in oilsands developments north of the City of Fort McMurray and in the Cold Lake area.

3.1.3 Northeast Transmission and Distribution

The Fort McMurray area connects to the transmission system via three 240 kV transmission lines. Under typical operating conditions, average exports from the area are approximately 285 MW. Load growth in the area will likely remain high, despite the oilsand project delays caused by the recent recession. It is expected that new load will be developed in concert with on-site generation, keeping the electricity supply-demand balance fairly consistent in the short term. This on-site generation will be predominantly *baseload* (operated 24 hours a day, seven days a week) co-generation.

These baseload additions will allow the region to retain reliable electricity supply. The area had three real-time *congestion* occurrences in 2008 and seven congestion events from January to September 2009. Congestion occurs when some electricity cannot be transmitted from one area to another due to insufficient capacity of transmission lines. Also in the short term, more voltage support devices will be added over the next two years to ensure system stability. Two 500 kV lines to Fort McMurray are on the longer-term government CTI list as part of the Electric Statutes Amendment Act, with an immediate addition of a 240 kV link scheduled for 2013.

Currently, the Cold Lake area has surplus generation, with constraints on the transmission system being managed through special protection schemes. It is anticipated that new oilsands projects will be built in the area over the next 10 years, which will result in increased electricity demand and bring more supply-demand balance into the region.

SECTION SUMMARY:

The Northeast region has been a high growth area, and will continue to experience growth in electricity demand. This is primarily due to industrial projects in the oilsands and forestry sectors. Northeast supply will continue to grow with co-generation projects being developed to support the oilsands industry. The government plans on building two large, 500 kV transmission lines from the Heartland area to Fort McMurray.

The plan is to stage these lines based on growth in demand and supply with initial construction to add a 240 kV line to Fort McMurray. Of particular importance for the staging will be the offsetting of demand growth with local co-generation development that will be used to supply steam and power.

3.2 Northwest Region

The Northwest region of Alberta includes Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grande Cache, Valleyview, Fox Creek and Swan Hills planning areas but not the Wabamun Lake area. It represents approximately one-third of the area of the province, with only one tenth of the total demand on the electric system. Region boundaries, as denoted for the purposes of AESO planning are outlined in Table 9 below:

Direction	Boundary
North	Northwest Territories Border
East	Fort McMurray and Athabasca
West	B.C. Border
South	Hinton and Wabamun

Table 9: Northwest Region Boundaries

3.2.1 Northwest Supply

Generation in the Northwest region is predominantly natural gas-fired with the HR Milner the major coal-based exception, including the generators listed in Table 10:

Generator	Capacity
Rainbow • Units 1,2,3,5 and Rainbow Lake	1. 26 MW 2. 40 MW 3. 21 MW 5. 47 MW Rainbow Lake: 47 MW
Fort Nelson	47 MW
Poplar Hill	47 MW
Valley View • Unit 1 • Unit 2	 1. 45 MW 2. 47 MW
Northern Prairie Power Project	93 MW
H.R. Milner	143 MW
Bear Creek	80 MW
Northstone	12 MW
Grand Prairie Ecopower	25 MW
Sturgeon	18 MW
P&G Weyerhauser	11 MW

Table 10: Generators in the Northwest

In total, the Northwest region contains only 770 MW of installed generating capacity. There is significantly more load than generation and this imbalance results in typical imports of between 530 and 755 MW from the Wabamun Lake and Fort McMurray areas.

The AESO has contracted Transmission Must Run (TMR) services in the region to ensure a minimum amount of generation stays online and power transfers into the region are kept within operating limits. TMR contracts are offered to generators when load growth exceeds the combined capability of transmission lines into a region and the available generation within that region. TMR is generally a temporary solution until new transmission can be built; however, in some instances it may be a long-term solution at lower overall cost.

Generating units that have TMR contracts may be required to operate when the hourly AESO price is below their cost of production. During these times the generator will receive

supplemental payments to cover the added costs. TMR opportunities will continue to be a potential option to stimulate additional generation in the Northwest.

3.2.2 Northwest Demand

The Northwest region contains approximately 1,100 MW or 11 per cent of the provincial peak load.

Annexed to the Northwest region of Alberta, and included in AESO demand forecasts, is the Fort Nelson area of British Columbia. The connection from Alberta to Fort Nelson was built in 1991 to service the growing electricity demand in the area, which was not serviceable by BC Hydro. Fort Nelson customers were treated similarly to direct connect customers in Alberta up until 2000. The continued demand growth in the Fort Nelson area resulted in need for TMR contracts in Alberta to service the area because transmission from the south was constrained. The connection to Fort Nelson is not treated as an intertie (resulting in importing/exporting rules applying) but as a part of the AIES system.

The AESO's 2007 Reference Load Forecast and Scenarios identified a customer demand growth potential of up to an additional 60 MW to 70 MW in Fort Nelson by 2013. Growth is anticipated due to increased development in the oil and gas sector, although this demand growth could either be served by gas or electric drives/equipment. Firm supply is currently less than 30 MW and this potential electric demand growth represents an approximate 200% increase.

3.2.3 Northwest Transmission and Distribution

The Northwest region is connected to the Wabamun Lake area via three 240 kV transmission lines, and to the Fort McMurray area via one new 240 kV transmission line.

The Fort Nelson / Rainbow Lake area is transmission constrained both internally and externally to the AIES. TMR services are required in the Rainbow Lake area 100 percent of the time.

The Grande Prairie area also does not have sufficient local transmission capacity. In order to compensate for this, TMR services are required approximately 54 percent of the time for both energy support and dynamic VAR support – a need for system stability.

Over the next two years, the following transmission projects are planned:

- Additional 144 kV transmission lines within the Northwest region; and
- Two Static VAR Compensators (or SVCs). An SVC is an electrical device used to provide fast-acting reactive power on high-voltage electricity transmission systems.

These additions are intended to improve area transfer capability and voltage control. Rainbow Lake area reinforcements are expected to reduce the need for TMR. Future generator in this area may also reduce the need for TMR.

SECTION SUMMARY:

The Northwest region is expected to sustain growth in electricity demand in the near future. Currently, the region has significantly more demand than generation, resulting in imports from Lake Wabamun and Fort McMurray. The Northwest has some transmission constraint issues, which limit the amount of electricity that can be brought in from other regions, and voltage support concerns, which make the system less stable and reliable.

4. Options and Opportunities for Northern Alberta

There are two principle opportunity areas for Northern Alberta electricity: generation development and energy efficiency programs. Generation options range from large-scale developments in hydro and co-generation to smaller scale renewable and district energy projects. Energy efficiency options range from load-based support to the overall grid to investments to reduce consumption

This section examines these options and identifies the nature of the opportunities for the North.

4.1 Generation and Grid Support

4.1.1 Conventional Generation Development

Large-scale generation options are influenced by three factors:

1. The proximity of fuels in particular wind, water and coal;
2. The relative carbon content of each fuel and future carbon emission policies; and
3. The proximity of loads and/or transmission resources.

The impacts of these factors are illustrated in Figure 14. The following definitions are relevant to this Figure:

- ***Super Critical Coal*** power plants operate at temperatures and pressures above the "critical" point of water (the point at which the liquid and gas phases of water coexist in equilibrium, at which point there is no difference between water gas and liquid water). This results in higher efficiencies – above 45% – meaning that Super Critical Coal plants require less coal per MWh, leading to lower emissions (including CO_2 and mercury), higher efficiency and lower fuel costs per MW.

- ***Natural Gas Combined Cycle (NGCC)*** facilities use advanced power generation technology to improve the fuel efficiency of natural gas. A gas turbine generator produces electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine.

- ***Integrated gasification combined cycle (IGCC)*** is a technology that converts coal into synthesis gas, called syngas, and subsequently removes impurities from the coal gas before it is combusted. This results in lower emissions of sulfur dioxide, particulates and mercury. Excess heat from the primary combustion and generation is then passed to a steam cycle.

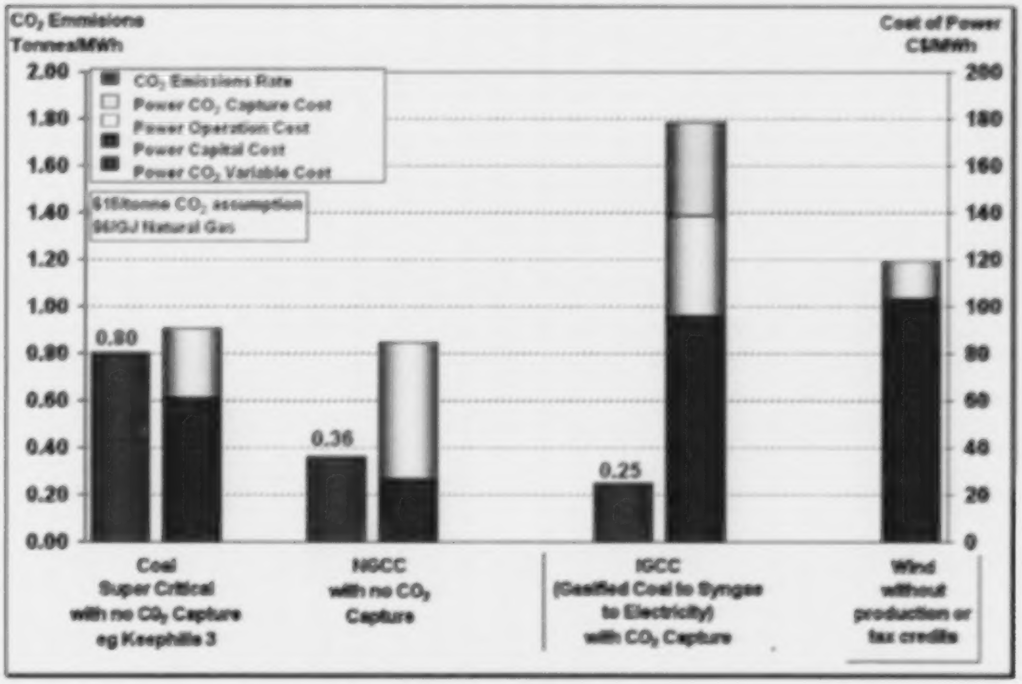


Figure 14: Generation Alternative, Costs and Carbon Outputs

The following key points arise from this chart:

- ***Super Critical Coal*** facilities result in 0.8 tonnes of carbon per MWh of output at a cost of $90/MWh. These facilities are constrained to coal production areas. The price of coal is generally fixed by long-term contracting arrangements at around the price of mining the coal. Because the coal price is fixed, the price to produce electricity is less variable.
- ***Natural Gas Combined Cycle (NGCC)*** facilities produce 0.36 tonnes of carbon/MWh at a cost of $85/MWh at a $6.00/GJ gas price. Other modeling suggests that this price could be as low as $65/MWh, as outlined in Section 4.7.6. Combined Cycle plants have added flexibility in terms of location and access to transmission resources since natural gas can be transported to the generation facility;
- ***Integrated gasification combined cycle (IGCC)*** with carbon capture can allow for closer proximity to loads, but will cost in the $175/MWh range when carbon capture is added with a commensurate reduction in carbon output to 0.25 tonnes/MWh;
- These three options can be compared to ***wind*** with zero carbon output; however, wind has a cost of $120/MWh including enhanced dispatch reliability and is constrained to high wind resource areas, generally with transmission access constraints.

A February 2010 review of the Alberta market situation by Macquarie Research indicates that the current Alberta forward power prices would only support development of natural gas projects given that gas stays in the $5.00 to $7.00/GJ range. The Macquarie analysis indicates that at a 10% return on capital, a combined cycle gas facility would need $60/MWh to break even at $5.00/GJ for gas and $73/MWh for gas at $7.00/GJ.

This report indicates that going forward; wind, hydro, and super critical coal will not be developed at these price levels without subsidies. The Macquarie Report further indicates that at 10% return on capital, the following break-even prices are required:

- Wind: $95/MWh;
- Hydro $89/MWh; and
- Super critical coal $90/MWh. *Note that the price of coal as a fuel is generally fixed for the projects, based on the long-term mining costs for recovery.*

Wind and hydro projects have added value as they generate carbon offsets as discussed in Section 4.4. The Macquarie Report concludes that Alberta may need to undertake a market re-structuring to attract the necessary capital to sustain conventional power generation investments.

4.1.2 Renewable Energy Development

There are considerable renewable energy development opportunities in Northern Alberta. Some potential projects have received significant attention from major project developers, while others remain unexamined due to transmission and other regional limitations.

One of the biggest renewable energy projects in development is the large-scale hydroelectric project at Slave River. It has a projected capital cost of $5 Billion for 1,250 MW of capacity. At a 70% utilization factor, this would result in electricity production costs of around $85 to $90/MWh. Slave Hydro will require a significant transmission build to Fort McMurray to allow for full integration into the grid

The Northwest region has significant wind resource potential along the foothills; however, there is limited transmission access available to make large wind farms in this area viable. Smaller-scale renewable, and alternate fuel resources offer significant opportunities, particularly if the electricity can be used locally and help alleviate transmission concerns.

4.1.3 Ancillary Services Opportunities

Ancillary services opportunities are generally for local system support and/or as offsets to transmission constraints. New transmission builds will reduce TMR opportunities, however regional operating reserve opportunities will remain. As mentioned in Section 2.1.4, electricity projects in the Northwest in particular, should consider both energy revenue and ancillary services revenue opportunities.

SECTION SUMMARY:

Three key factors will influence future generation development in Alberta:

1. Implications of carbon offset pricing for traditional coal development;

2. Long-term prices for natural gas and their impact on co-generation and combined cycle gas plant development; and

3. The long-term pricing structure for power contracts in Alberta.

Northern Alberta may benefit from the development of new natural gas-fired and hydro-electricity generation projects, provided that additional transmission capacity is added as contemplated.

4.2 Smart Metering and Demand Side Management

4.2.1 Advanced Metering Infrastructure (AMI)

In May, 2008, Alberta Energy released a discussion paper entitled: "New Energy Efficiency Opportunities for Albertans Through Advances in Metering". The primary objectives of this discussion paper can be summarized as follows:

- Ensure that retailers and consumers:
  - Have access to information of value in product development and innovation; and in their efforts towards **energy efficiency**;
  - Are not unnecessarily burdened by a need to access dissimilar interfaces, terms and conditions, and standards among distributors;
- Ensure that Albertans have access to conservation information and technologies where it is practical to do so; and are not unnecessarily burdened with duplicate costs as distributors of natural gas and water engage advanced metering.

Since the 2008 discussion paper was released, the AMI initiative has been expanded to include residential and farm customers.

The Guiding Principles of the AMI Initiative are outlined in Table 11 below:

No.	Principle
1	Maximize opportunities and effectiveness for energy management and conservation.
2	Minimize transaction costs to market participants operating in Alberta. Interfaces to data and features of AMI as utilized by customers and retailers will be as simple and effective as possible, allowing for a single means of communicating with all AMI systems in Alberta through a set of universal inter-corporate electronic transactions.
3	Expedite and improve the accuracy of load settlement, billing functions, and the customer switching process.
4	Retail markets and customer choice will be enriched.
5	Enable more efficient and effective distribution systems.
6	Change should be specified using the "lightest possible touch" required to be effective.

Table 11: Alberta Energy Guiding Principles of AMI

In January, 2010 the Electricity Branch of the Alberta Energy released its "Straw Model – Advanced Metering Infrastructure" document, compiled by Bob Deyl of DEYL Group Limited.

The AMI initiative is intended to provide Alberta with an entry point to realize the benefits of a 'smart grid' including potential savings in meter readings, a broadening of offerings by retailers, inducements to energy efficiency, enhanced carbon emissions sensitivity and improvements to network effectiveness. For more information on the government's AMI initiative, refer to Appendix 3.

SECTION SUMMARY:

Harnessing AMI to achieve energy efficiency and conservation benefits may be achievable over the next five years; however, the benefits will be largely confined to the 40% of load that is currently on conventional meters. Opportunities for energy efficiency and conservation for industrial loads will require development of specific programs by industry and the AESO.

4.3 Energy Efficiency and Conservation

Encouraging energy efficiency is a priority objective for Alberta Energy. Energy efficiency is often considered a subset of energy conservation, along with three other categories, as outlined in Figure 15.

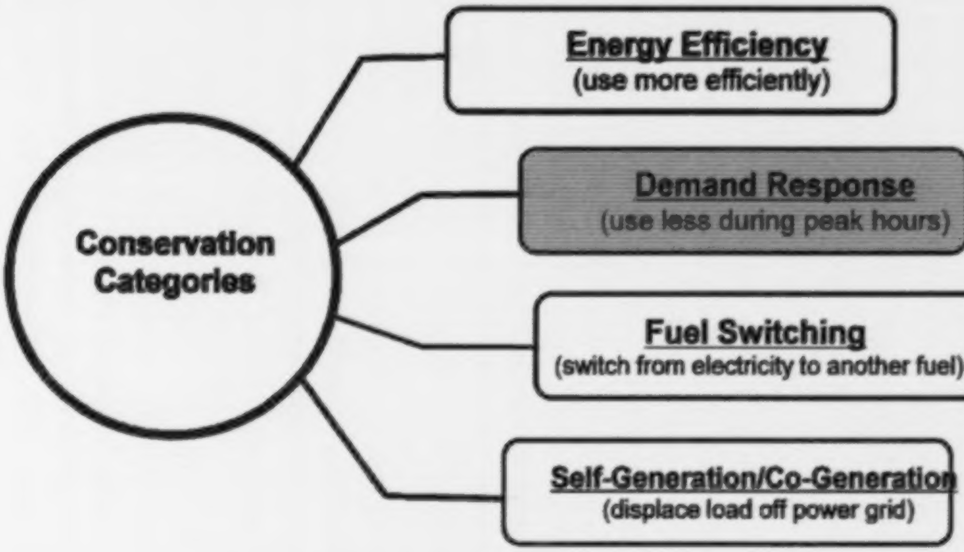


Figure 15: Conservation Options for Energy Efficiency

Demand response is a target for short-term programs including load reduction and load shifting. Fuel switching is moving from electricity to natural gas (or vice versa) and to alternate sources such as solar heating or geo-thermal. Self-generation can be large-scale such as industrial co-generation or small-scale such as micro-generation projects. The intent of micro-generation is to displace supply from the grid. Conservation programs need to target the economics of each conservation source.

Energy Efficiency

Alberta Energy's objective is to develop programs to incent efficient use of energy and provide carbon offsets. Programs will likely be voluntary and directed to peak energy use in the short-term. Longer-term programs will be directed to building codes and energy efficient appliances and will likely be adapted from other jurisdictions.

Demand Response

AESO operated Demand Response (DR) programs in Alberta have existed for the past fifteen years and have all been driven by the AESO as reliability products to alleviate short-term system constraints. In total, Alberta has 300 to 500 MW of load that can respond to appropriate triggers from the AESO or the market. Many loads have lost interest in participating in DR programs because power prices are lower than they have been in previous years, and there is limited effort being made to engage loads in active market participation. However, with added emphasis from policy makers, the AESO and industrial associations, DR has the potential to serve as both an economic tool and a reliability mechanism. Demand response as a tactical tool for supporting the electrical grid offers new opportunities in Alberta. DR services could include load shed support to imports (to increase the transfer capability on the interties), wind following and regional programs in transmission constrained areas – such as Northwest Alberta.

Fuel Switching

Some fuel switching between gas and electricity does occur in Alberta, such as irrigation pumps being switched from natural gas to electric power in the southern Alberta irrigation areas. Fuel switching in Alberta is not as common as other jurisdictions because the price of power is related to the price of natural gas. In Alberta, the forward power price curve is driven by natural gas forward prices since over 45% of the generating capacity in Alberta is natural gas-fired.

Fuel switching is not likely a long-term economic solution for Alberta consumers. Despite this, the use of alternate fuels for energy generation may have merit. The use of biomass as an energy generation fuel is examined in a Section 4.5.3.

Self-Generation

On a large industrial scale, self-generation is a popular option, particularly as part of Industrial Systems Designations (ISDs), as discussed in Section 2.5. Self-generation for remote or transmission-constrained areas is a viable alternative in many instances to new transmission builds. However, it is inhibited by policy and market obstacles. Uniform transmission rates and lack of regional pricing for power seriously limit the economics of local generation projects. Small-scale micro-generation projects are allowed in Alberta, but have no special incentives to encourage their development at this time.

4.3.1 Industrial

Industrial loads in Northern Alberta should become the target of all forms of energy efficiency and conservation projects. Many industrial loads have the ability to support a full range of products, including energy efficiency retro-fits, demand response for short-term load shedding and support for other reliability products. Industrial loads also have potential for heat recovery systems for local generation. There is currently an absence of programs that incent these types of programs, as well as several market policy and regulatory barriers that are prohibiting these types of programs from evolving on their own. These barriers will be discussed in Section 5.

4.3.2 Commercial and Residential

Commercial and residential loads account for approximately 35% of Alberta energy consumption. The Provincial Energy Strategy has specific objectives to encourage greater energy efficiency and conservation in both the short and longer term. The Advanced Metering Infrastructure initiative is anticipated to be a cornerstone for these energy efficiency programs and is to be implemented over the next five years. Experience in other jurisdictions with AMI and smart grids have led to billing and cost reductions through improved meter reading and to some energy efficiency during peak usage.

In Alberta, it is more difficult to achieve any significant reductions to peak energy consumption due to the short-term pricing dynamics and the limited scope for energy reductions in the winter. However, longer-term programs directed to on-site energy generation and to energy efficiency through building codes and energy efficient equipment is expected to reduce consumption from both residential and commercial facilities.

SECTION SUMMARY:

There are various categories of energy conservation, including: energy efficiency, demand response, fuel switching and self-generation. While fuel switching has little merit in Alberta, the other three options are viable and would be economic solutions under an appropriate incentive regime. A coordinated program is needed if success is to be achieved.

4.4 Carbon Policy

Alberta's energy sector is highly dependent on the production of hydro-carbon fuels and products. Because of the abundance of hydro-carbon resources, Alberta's power generation sector is heavily dependent on carbon-based fuels such as coal and natural gas. With global concerns over climate change and the use of carbon-intensive fuels, both the provincial and federal governments have developed strategies to reduce carbon emissions. These strategies, and the programs that are being developed to support them will affect the future costs of power.

This Section explores the various renewable generation and carbon offset programs that should be seen as opportunities for Northern Alberta.

4.4.1 Renewable Generation Incentives

In Alberta, there are some voluntary methods for electricity consumers to "green up" their consumption. Consumers can produce green energy themselves, buy their electricity from a green energy retailer, or buy Renewable Energy Certificates (RECs) to match their consumption level. A REC is produced for each unit of electricity that is produced by a renewable or "green" generator. This generator then sells his electricity into the AESO hourly or forward market, and can sell his REC to a broker or traders or supplier (green retailer) and ultimately to the end consumer, as illustrated in Figure 16.

The REC does not have to be produced at the exact time the consumer is using electricity, instead the total electricity volume the consumer uses in a month is usually matched in volume of RECs.

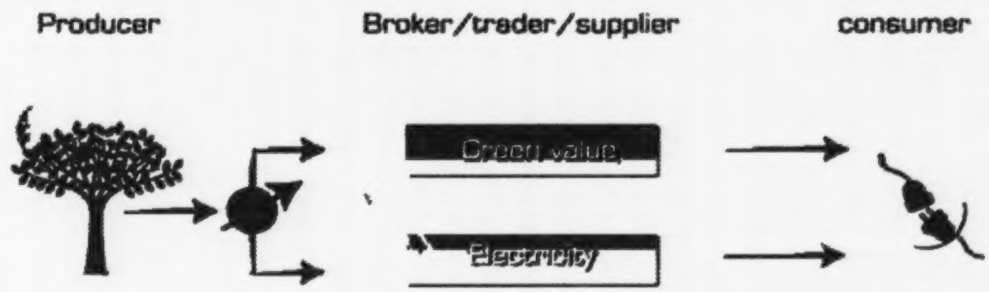


Figure 16: Renewable Energy Certificates

REC markets provide a mechanism to allow developers of renewable energy to capture value for displacing generation from carbon based sources.

Green energy retailers offer renewable electricity contracts to Alberta consumers. There are several green energy retailers in Alberta, including:

1. Just Energy Alberta L.P. (Just Energy);
2. Bullfrog Power; and
3. ENMAX Energy Corporation (including EasyMax and Greenmax).

Some of these retailers supply electricity and the "greening up" RECs, while others simply supply the RECs and the consumers receive either the Regulated Rate or a contract rate for electricity. For example, Bullfrog Power will "green up" a household's electricity consumption for 2¢/kWh, and the household will continue to pay their electricity bill through their current supplier.

Some of these retailers ensure that the RECs are from local projects and are EcoLogo certified (to ensure they achieve an appropriate level of "greenness")

Federal Incentives

Current federal programs and policies intended to boost renewable energy development that are applicable to Alberta include the following:

1) *ecoEnergy for Renewable Power*
    - Provides an incentive payment of 1 ¢ per kWh for up to 10 years for low-impact renewable energy projects constructed between April 1st, 2007 and March 31st, 2011.
2) *Amendments to Class 43.1: accelerated depreciation for capital spending on alternative energy sources*

- Qualifying equipment acquired between February 23rd, 2005 and December 31st, 2011 that falls into set criteria for cogeneration systems or renewable energy generation systems is eligible for a 50% Cost of Capital Allowance depreciation rate for tax purposes.

3) *Canadian Renewable and Conservation Expense (CRCE)*
   - Provides a tax deduction for expenses incurred to set up a renewable or energy efficiency system.

4.4.2 Greenhouse Gas (GHG) Offset Markets

Alberta's current aggregate generation mix produces a provincial grid average of 0.88 tonnes of CO2 equivalent per MWh based on 2008 data. In Alberta, more electricity is generated by coal plants than by natural gas plants and cleaner sources of generation, resulting in a relatively high grid average, as illustrated in Figure 17 below:

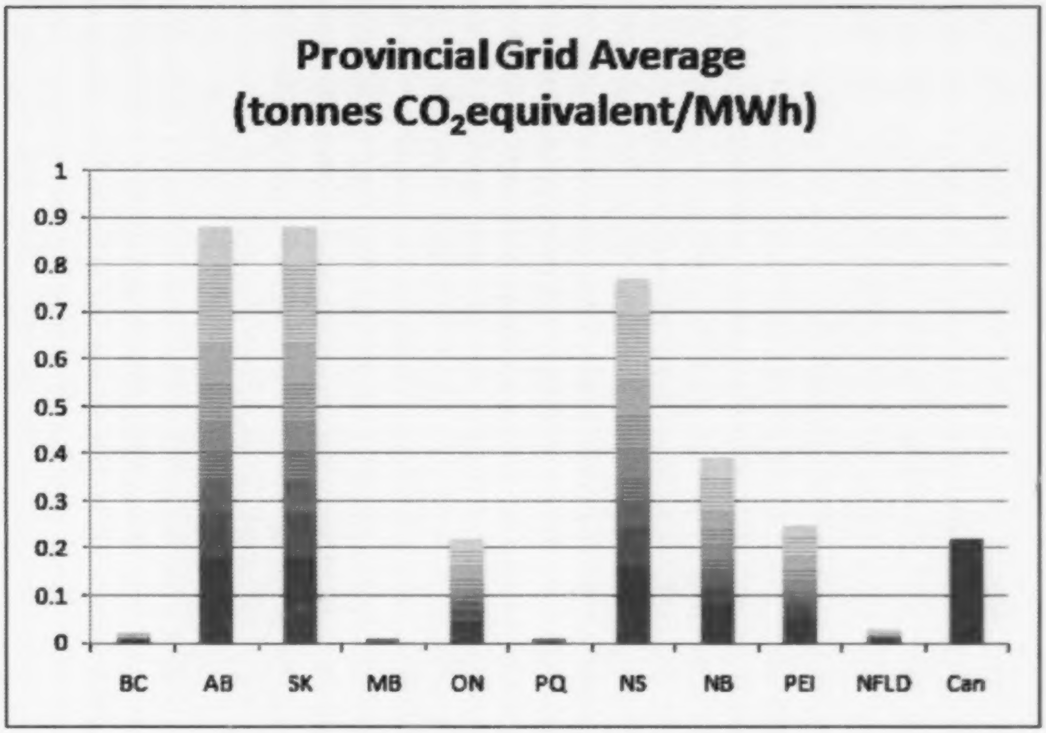


Figure 17: Provincial Electricity-related Carbon Emissions

In order to counter-act this high carbon intensity, Alberta implemented a regulatory system for GHG emissions on July 1, 2007. This regulatory regime is explained below.

Specified Gas Emitters Regulation

This regulation enables a compliance-based carbon market to develop in Alberta by establishing demand and supply as follows:

Market Sector	Description
Demand	• Regulated emission reductions targets are set for large emitters. • These large emitters can buy verified emission reductions and/or GHG "offsets"
Supply	• Emission "offsets" are allowed as a compliance option for regulated emitters

Table 12: Alberta Specified Gas Emitters Regulation

An *offset* (also called "*carbon credit*") is a reduction or removal in GHG emissions from a project that features a new management practice, technology and/or control system. This market-based approach to managing GHG emissions allows for flexibility to achieve carbon targets and innovation in developing new, greener technologies.

Figure 18 illustrates Alberta's overall Climate Change Strategy in terms of emissions reductions. Greening energy production (which includes electricity production) is intended to save 37 mega-tonnes of carbon.

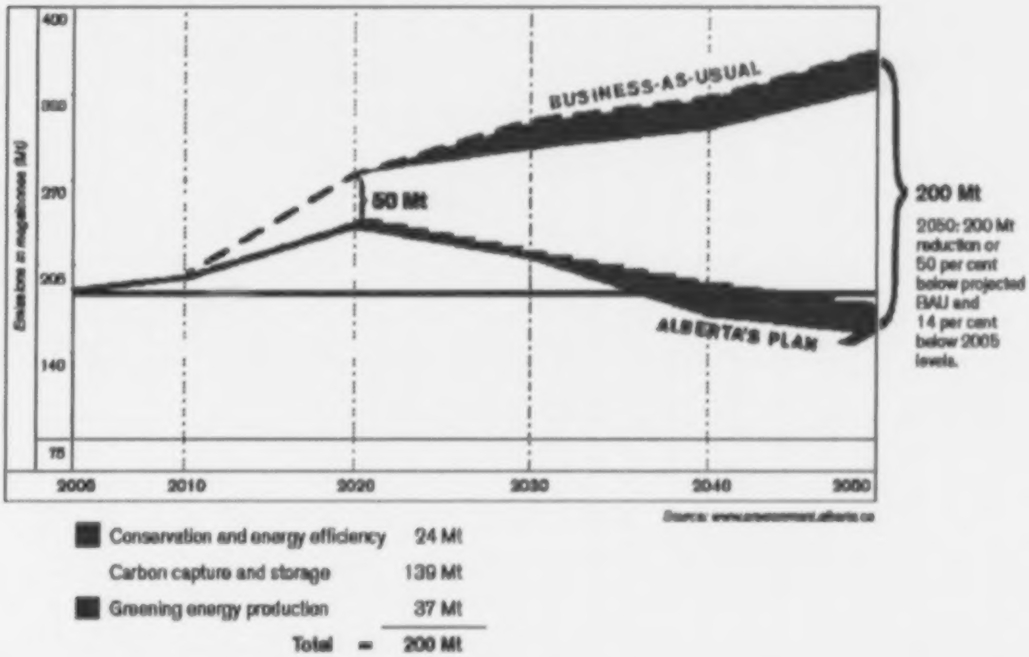


Figure 18: Carbon Emissions and Alberta's Climate Change Strategy

New electricity supply projects with sufficient environmental consideration could earn up to $15/MWh in credits from greenhouse gas (GHG) offsets if they are designed appropriately. This additional revenue stream could change the economics of a project.

Developing an effective forward contracting market for small-scale renewable generators will help make these projects economic. This may include the development of long-term power purchase arrangements that include energy and renewable offsets, as well as consideration for "bulk energy" products that would allow intermittent, renewable generators to sell a volume of electricity, irrespective of the time of day the electricity is produced. Natural gas generation and *demand response* could be used to "firm up" this intermittent generation.

SECTION SUMMARY:

Alberta is developing policies that encourage renewable generation and discourage carbon emissions. New renewable and low-emission generation projects can earn additional revenue streams by selling Renewable Energy Certificates (the "green" component of renewable electricity) and/or carbon offsets. Further work needs to be done to make forward contracting easier and more efficient for small-scale renewable generators.

4.5 Fuel Alternatives

Electricity generation project size is critical to the economics of the project. For the purposes of this report, project sizes will be divided into three main categories:

- Large projects – greater than 50 MW;
- Intermediate projects – between 1 MW and 50 MW; and
- Small projects – less than 1 MW.

Micro-generation is a subset of "small projects". In order to be classified as micro-generation, a project must meet the criteria outlined in Section 4.6.1.

This Section examines the various fuel alternatives for new electricity generation projects. The focus is on large and medium projects that municipalities or other Northern Alberta organizations can potentially implement. Micro-generation will be examined in Section 4.6. For the purposes of comparison, the various fuel alternatives will be described using the evaluation criteria in Table 13:

Criteria	Description
Location Flexibility	• How flexible the location of generation is relative to demand.
Utilization Factor and Dispatchability	• The percentage of hours of the year that the resource is available at maximum capability; and • Is the resource dispatchable in the short term (within 2 hours of use)?
Cost to Build	• The capital cost per MW of capacity.

Cost to Operate	•	The operating costs per MWh of output.
Carbon Impact	•	The carbon intensity or potential for earning carbon offsets.
Impact on Transmission	•	The impact on transmission utilization.
Reliability Impact	•	Is the resource a user or contributor to system reliability?

Table 13: Resource Evaluation Criteria

4.5.1 Wind Power

Wind energy is considered the most commercially attractive low-impact renewable energy source, but is not necessarily always financially viable. The wind energy industry has experienced significant growth, particularly over the past decade. This growth has led to improvements in technology, operation, maintenance, and wind forecasting capabilities.

When many wind turbines are installed in close proximity, the development is called a wind farm. Part of a wind farm is depicted in Figure 19.

Figure 19: Wind Farm

[Photo: A. Bellissimo, used with permission]

Wind farms can be developed and brought into commercial operation on a very fast timeline. If regulatory issues are limited, the timeline can be as short as three years. Currently, Alberta has about 630 MW of installed wind generating capacity. A rough estimate of Alberta's total wind energy (theoretical) potential is about 64,000 MW.

One of the disadvantages of wind energy is that it must be transmitted from generation sites, which are typically remote, to the dominant sites of energy use, which are typically urban centres. The rural electricity transmission and distribution systems that are proximate to wind farms are generally insufficient to carry the output from the wind farms. This means that major and expensive system upgrades can be required in order to take advantage of the best wind regimes.

Table 14 provides an overview of wind energy characteristics. Wind power operating costs include labour, oil changes, and blade and equipment repairs.

Criteria	Wind Energy
Location Flexibility	• Specific to wind areas
Utilization Factor and Dispatchability	• 35% to 40% utilization factor • Wind is non-dispatchable and is not necessarily coincident with high demand levels
Cost to Build	• \$2.4M per MW
Cost to Operate	• \$12 to \$15/MWh
Carbon Impact	• Wind energy can earn Renewable Energy Certificates (RECs) or carbon offsets, equivalent to \$15 - \$20/MWh
Impact on Transmission	• Transmission is generally the constraining factor in wind energy development. • Wind energy's low utilization results in under-utilization of transmission lines.
Reliability Impact	• for the rate that wind ramps up and down.

Table 14: Wind Energy Characteristics

4.5.2 Hydro

Canada has a rich history of developing hydroelectric resources, and approximately 60% of the country's electricity comes from hydro. There are two main types of hydro projects: dams/reservoirs and run-of-the river projects. Both these have advantages and disadvantages, as outlined in Table 15:

Project Type	Advantages	Disadvantages
Dam / Reservoir	• Flexibility; and • Can respond to system control request for dispatch	Larger environmental impacts
Run-of-the-river	• Reduced environmental effects	• Less reliable due to dependent on the seasonal flow of rivers

Table 15: Hydro Project Advantages and Disadvantages

Figure 20 illustrates a hydroelectric dam / reservoir:

Figure 20: Hydroelectric Dam

[Photo: V. Bellissimo, used with permission]

Table 16 provides an overview of hydroelectric characteristics.

	Hydroelectric Energy
Location Flexibility	• Constrained by geography.
Utilization Factor and Dispatchability	• 50% to 60% utilization factor for run-of-river projects, less for projects with dam storage / reservoir. • Projects with dams and reservoirs are dispatchable; whereas run-of-river projects are not.
Cost to Build	• \$4M to \$5M per MW
Cost to Operate	• **\$5 to \$6/MWh**
Carbon Impact	• Small hydro projects can earn Renewable Energy Certificates (RECs) or carbon offsets, equivalent to \$15 - \$20/MWh. • Larger hydro projects may be ineligible to earn RECs.
Impact on Transmission	• **Transmission can be a constraining factor in hydroelectric development.**
Reliability Impact	• Hydroelectric energy, particularly dam/reservoir projects, tends to improve system reliability. • These types of projects can provide ancillary services such as regulating reserve (automatic generation control).

Table 16: Wind Energy Characteristics

4.5.3 Biomass

"Biomass" refers to a range of fuels including:

- Timber;
- Agriculture and food processing wastes;
- Fuel crops – grown specifically or reserved specifically for electricity generation;
- Sewage sludge; and
- Animal manure.

Most biomass electricity generation projects burn lumber, agricultural or construction and demolition wood wastes. There are two processes used to generate electricity:

1. Direct Combustion
   - Biomass fuels are burned directly in boilers that supply steam to steam-electric generators. The generators are the same type used to burn fossil fuels.
2. Gasification
   - Biomass is converted into methane, a gas that fuels either steam generators, combustion turbines, combined cycle technologies or fuel cells. Gasification is much more flexible than direct combustion because the methane can be used in many different systems.

Biomass-fuel electricity produces carbon dioxide emissions; however, it is considered "clean" because it only releases carbon that was previously absorbed from the atmosphere. Effectively, it is a net-zero emission process. If the biomass were to decompose naturally, it would release methane, which is more potent than carbon dioxide in terms of global warming potential.

There are currently five biomass electricity projects, totaling 178 MW, in Alberta. The dominant fuel type is wood waste from pulp and saw mills.

Table 17 provides an overview of biomass energy characteristics.

Location Flexibility	• Constrained by geography.
Utilization Factor and Dispatchability	• **80% utilization factor.** • **Most projects are dispatchable.**
Cost to Build	• $1M to $2M per MW
Cost to Operate	• **$30 to $50/MWh – dependent on cost to acquire fuel.**
Carbon Impact	• Biomass projects can earn Renewable Energy Certificates (RECs) or carbon offsets, equivalent to $15 - $20/MWh.
Impact on Transmission	• **Some projects can be moved to better transmission zones, although the cost to move fuel often limits this.**
Reliability Impact	• Due to their dispatchable nature, Biomass projects can improve system reliability.

Table 17: Biomass Energy Characteristics

Landfill Gas

Landfill gas is typically comprised of around 60% methane and 40% carbon dioxide. It is produced when organic materials, including food waste and paper products, decompose. Large municipal or industrial landfills produce sufficient gas that electricity generation is possible. Landfill gas is collected by drilling wells into landfills and collecting the gas through a system of pipes. The gas is then processed and often combined with natural gas to fuel combustion turbines and generate electricity. Landfill gas electricity generation can use conventional combustion turbines or small combustion or combined cycle turbines.

The methane that is used in the process would otherwise either be flared or released into the atmosphere. Landfill gas electricity generation is an excellent option from a GHG perspective because methane has about 23 times the global warming potential of carbon dioxide. The carbon credits associated with the methane destruction process alone often make the landfill gas project viable financially.

Figure 21 illustrates the Trail Road Landfill Gas Plant, located near Ottawa.

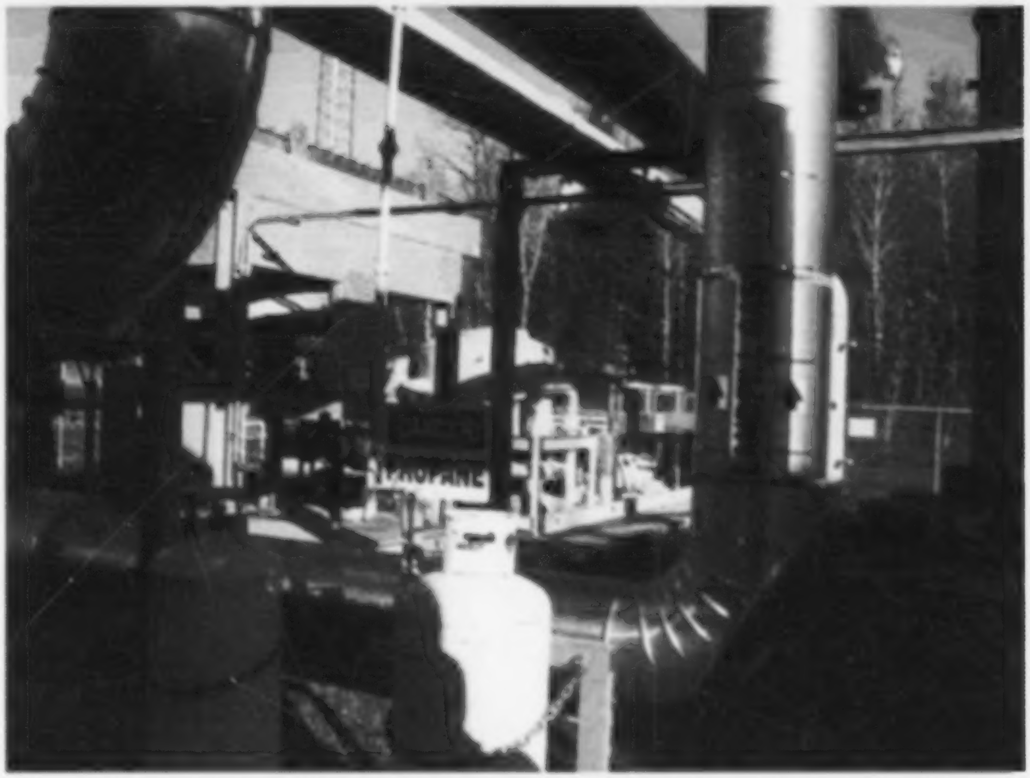


Figure 21: Landfill Gas Plant

[Photo: V. Bellissimo, used with permission]

Table 18 provides an overview of landfill gas energy characteristics.

Location Flexibility	• Constrained by geography – projects are located at landfill sites.
Utilization Factor and Dispatchability	• 80% utilization factor. • Projects provide baseload electricity and can be dispatched down.
Cost to Build	• Similar to biomass.
Cost to Operate	• Similar to biomass.
Carbon Impact	• Landfill gas projects can earn Renewable Energy Certificates (RECs) or carbon offsets, equivalent to \$15 - \$20/MWh for their electricity production, as well as carbon offsets for methane destruction. • Methane is a greenhouse gas approximately 23 times as potent as carbon dioxide.
Impact on Transmission	• Projects must be located at landfills, so transmission impact is dependent on transmission availability at landfill sites.
Reliability Impact	• Due to their consistent, baseload nature, landfill gas projects can improve system reliability.

Table 18: Landfill Gas Energy Characteristics

4.5.4 Geothermal

Geothermal energy is essentially heat recovery from the earth, used to produce energy from either of two main geothermal processes:

1. Hydrothermal:
   - Uses naturally occurring steam or hot water to spin a turbine and generate electricity.
2. Enhanced Geothermal Systems (EGS):
   - Geothermal wells are drilled deep into the surface of the earth (3-10 km in Alberta) to reach temperatures in excess of the boiling point of water. Water is pumped downward, turns to steam, and rises to the surface where it spins a turbine and generates electricity.

A prototype geothermal project in BC has an output capability of 100 MW. The potential for geothermal in Northern Alberta is largely unknown at this time and is most likely limited to heat exchange, rather than electrical generation as is illustrated in the Canadian geothermal potential map (Figure 22).

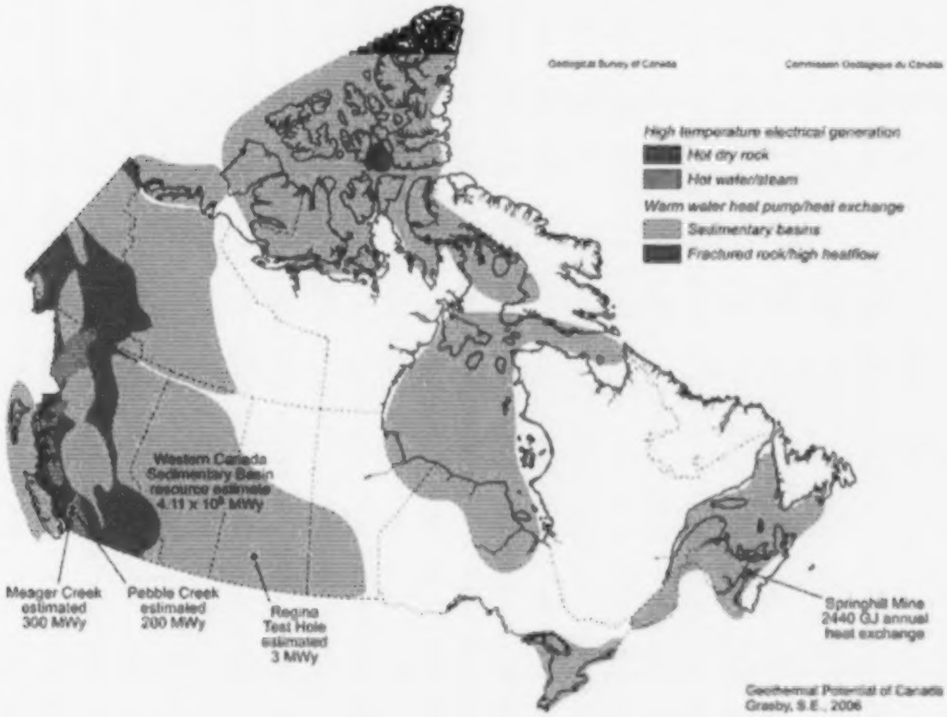


Figure 22: Geothermal potential in Canada

Table 19 provides an overview of geothermal energy characteristics.

Location Flexibility	• Constrained by geography.
Utilization Factor and Dispatchability	• 95% utilization factor. • Projects provide baseload electricity and can be dispatched down.
Cost to Build	• There are too few projects in existence to provide an accurate estimate of capital costs. • Technology is at the pilot project stage of development.
Cost to Operate	• There are too few projects to be able to estimate operational costs.
Carbon Impact	• Projects can earn Renewable Energy Certificates (RECs) or carbon offsets, equivalent to $15 - $20/MWh for their electricity production.
Impact on Transmission	• If sites are located proximate to oilsands operations, there may be transmission already available – or generation may be used on site, delaying the need for transmission build. • If sites are remote, transmission will be expensive.
Reliability Impact	• Baseload power will improve system reliability.

Table 19: Geothermal Energy Characteristics

The economics of geothermal are very attractive provided the heat source can be accessed in an efficient manner. A possible solution to this heat source requirement may be available from the technology used in the Swan Hills/Sagitawah in-situ coal gasification project.

In-Situ Coal Gasification (ISCG) is the gasification of coal deep underground in its original coal seam. The ISCG process uses injection and production wells drilled from the surface to access the coal seam and facilitate the process in-situ. The coal is not extracted to the surface, as there is no coalmine or coal handling facilities with ISCG. Through a high-pressure gasification process, the coal is efficiently converted in-place in its original seam into *syngas*. The *syngas* is flowed to the surface and is then processed in a conventional gas plant to produce fuel for electrical power generation or used to produce other products.

4.5.5 Co-generation

Co-generation, which is also referred to as *combined heat and power* (CHP), is using a heat engine or power station to generate electricity and heat simultaneously. While conventional power plants emit heat as a by-product of the electricity generation process, co-generation captures this heat for use in industrial processes or for district heating purposes. Co-generation is most efficient when the heat can be used on-site or proximate to the production site. The fuel used in co-generation is predominantly natural gas, but other fuels can also be used.

Table 20 provides an overview of co-generation characteristics.

Location Flexibility	• Not constrained by geography – can be sited where required.
Utilization Factor and Dispatchability	• 90+ % utilization factor. • Projects provide baseload electricity and generally do not want to be dispatched off due to steam requirements.
Cost to Build	• $1.3M per MW.
Cost to Operate	• Dependent on gas prices – non-fuel costs are approximately $20/MWh.
Carbon Impact	• 0.3 tonnes /MWh.
Impact on Transmission	• Flexible and a substitute for transmission.
Reliability Impact	• Can support full range of AS requirements.

Table 20: Co-generation Characteristics

SECTION SUMMARY:

There are various fuel alternatives open to Alberta, including wind power, hydro, biomass and landfill gas, geothermal and co-generation.

The most promising options for Northern Alberta are biomass, as it relates to the forestry and agricultural industries, and co-generation, as it relates to the oilsands industry.

4.6 Micro-Generation and Energy Storage

4.6.1 Micro-generation

The Government of Alberta issued the Micro-Generation Regulation on February 1, 2008, allowing micro-scale generators to receive credit for electricity they export into the electricity system.

In Alberta, micro-generation is defined as the generation of electricity from a unit that:

- Has a capacity of one megawatt (1 MW) or less;
    - For comparison purposes, a 1 MW wind project, operating at a 30% utilization factor could produce around 220 MWh per month – about the same amount that is consumed by 200-400 households.
    - A 1 MW biomass project, operating at an 80% utilization factor could produce around 600 MWh per month – about the same amount that is consumer by 600 – 1000 households.
- Is connected to the distribution system;
- Exclusively uses sources of renewable or alternative energy; and
- Has its energy output intended to meet all or a portion of the customer's electricity needs.

Micro-generation typically comes from sources such as solar photovoltaic (PV) and residential scale wind turbines. The term "*distributed generation*" refers to the use of many, small-scale micro-generation units, instead of large-scale, centralized power plants. Many governments around the world are implementing policies to encourage distributed generation, which is viewed as a "greener" alternative to the current electricity system structures. Distributed generation can reduce the need for transmission lines and can allow for added local reliability, reducing the risk of major widespread power failures. The use of micro-generation has the added benefit of encouraging energy awareness and raising energy literary, which leads to wiser use of electricity.

According to the Alberta Micro-Generation Regulation, electricity distributors must provide grid connection services for micro-generators with capacities less than 150 kW.

More information is available from the Alberta Utilities Commission website: http://www.auc.ab.ca/rule-development/micro-generation/Pages/default.aspx

Net Metering and Net Billing

In order to understand the economics of micro-generation revenue, it is important to examine the difference between net metering and net billing. These two concepts are defined in Table 21.

Net Metering	• The generator receives market (or contract) value for <u>any excess</u> electricity transmitted into the grid; • The electricity flow is recorded by a bi-directional electricity meter and netted over the billing period; and • Any differences are settled at the energy price in each hour.
Net Billing	• The electricity taken from the grid and the electricity transmitted into the grid are tracked separately; • <u>All electricity</u> transmitted into the grid is valued at a given price (market or contract); • <u>All electricity</u> consumed from the grid is acquired at the contracted or hourly price of electricity; and • The net bill is the financial difference between the cost of energy acquired and the price for energy generated.

Table 21: Net Metering and Net Billing

Figure 23 illustrates the Canadian jurisdictions that use net metering and net billing.

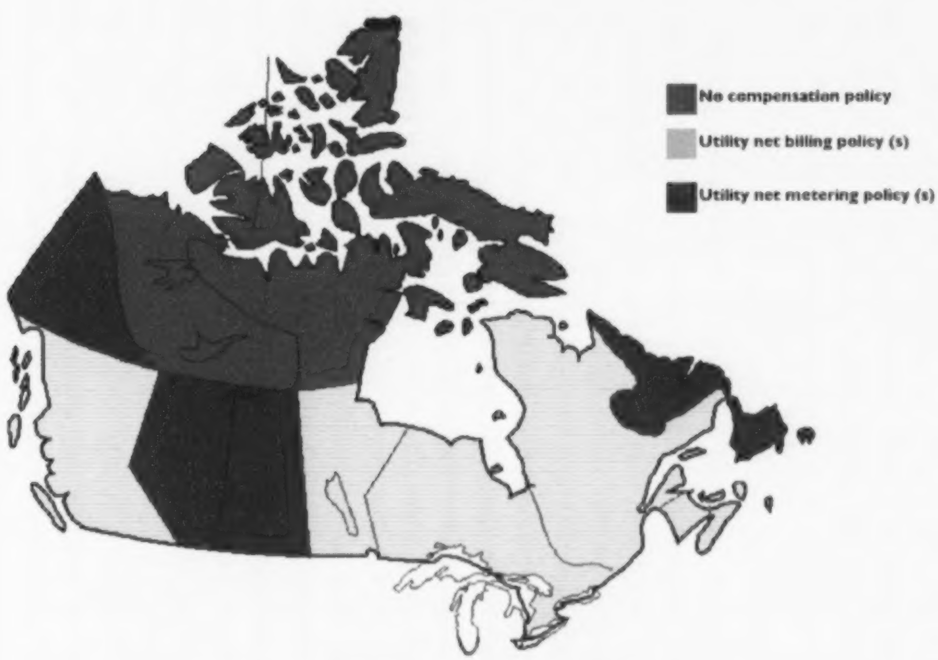


Figure 23: Net Metering and Net Billing, Canada (Dec 2008)

Net metering is used in provinces that do not have any special incentives for micro-generation projects and as such, the consumer is indifferent between the revenue for the micro-project and his cost of energy from the grid. This is the current practice in Alberta and is one of the obstacles to more extensive adaption of micro-projects.

Other provinces use a net billing process, wherein the energy being sold to the grid may have greater value than the energy consumed from the grid. This is the case where provinces, such as Quebec, Ontario, Manitoba and B.C., have implemented incentive pricing for small-scale generation projects that reflect location and carbon offset values.

One potential solution to encourage micro-generation in Alberta would be to implement net billing with a netting of transmission and distribution fees as well. This would mean that the micro-generator gets paid (either a contract or market price) for the full output of their generator. On the consumption side, they would pay the energy component of their bill (either the Regulated Rate or a retail contract rate) but would not pay transmission and distribution fees for the power that is supplied on-site.

Micro-generation should not be limited to the size of the consumptive load on-site and micro-generators should be credited for line loss savings. This solution will be explained further in Section 5.1.

Renewable Fuels

The two predominant renewable fuels used for micro-generation are solar photovoltaic (PV) and wind power. Some renewable technologies, such as hydro and biofuels make more sense economically in larger projects and rarely exist as micro-generation projects.

Solar PV converts the energy in solar radiation into direct current electricity. This is then converted into alternating current electricity using inverters and fed into the electricity grid. Solar PV systems are typically mounted on south-facing rooftops and only produce electricity during daylight hours.

Wind power can be harnessed on a micro-generation scale as well as a large industrial scale. Micro-generation wind turbines (typically 0.4 kW to 100 kW in capacity) are essentially smaller versions of large industrial-scale turbines (typically 1.5 MW to 3 MW – or 1500 kW to 3000 kW in capacity). Micro-generation wind turbines can be mounted on poles fastened by guy-wires, or installed on monopoles. Some micro-generation wind turbines are available from retailers such as Canadian Tire.

There are other, less commercial forms of micro-generation, including micro-cogeneration – using combustion engines and fuel cells – however, these are much less common than solar PV and wind power.

4.6.2 Energy Storage

The electricity system requires that supply instantaneously meet demand. With more intermittent sources of generation, such as wind power, being integrated into the grid, more solutions are necessary to ensure supply is there when needed. Electricity storage is one of these solutions.

Electricity is stored when generation exceeds consumption and the stores are used when consumption exceeds generation. There are various electricity storage options, including:

- Batteries:
  - Essentially large versions of small-scale batteries, with grid integration capabilities;
  - Large-scale batteries are generally expensive, have high maintenance costs and limited life spans.
- Electric Vehicles:
  - Can be used to store electricity since each vehicle has around a 20 to 50 kWh battery pack;
  - If the plug-in time period is coordinated using effective software, the electricity storage can be optimized;
  - This is not a mass battery solution yet, due to the small numbers of electric vehicles.
- Compressed air:
  - When compressed air is stored in old mines and other similar structures, it can be released and used to generate electricity in high demand periods.
- Flywheels:
  - Use mechanical inertia to store electricity.
- Hydrogen:
  - Hydrogen is produced (typically using electrical energy and/or heat), then sometimes compressed or liquefied, stored, and then converted back to electrical energy and/or heat.
- Pumped Storage:
  - Uses water to store kinetic potential energy, and works like a hydroelectric dam;
  - Pumped storage usually requires two nearby reservoirs at considerably different heights;
  - When it is economic, the pumped storage facility runs generation turbines in reverse, using electricity to pump water back up the channel and into the reservoir. This water can then be used during high demand periods to generate more electricity;
  - Some electricity used to run the pump, and there are losses, but overall, the efficiency of pumped storage is around 80%.

Most of these options are extremely expensive and uneconomic. The most cost effective mass electricity storage option is pumped storage. Capital costs for pumped storage facilities can be approximately $2 Million per MW. There are also costs associated with buying electricity during low demand hours in order to sell electricity during high demand hours.

SECTION SUMMARY:

Currently, there are insufficient benefits to encourage micro-generation in Alberta. Small-scale generators such as solar PV and residential scale wind are unable to capture the benefits of line loss savings, carbon credits (offsets) and transmission and distribution savings that they create.

On the energy storage front, the most effective option – pumped storage – is not being developed in Alberta because it is too difficult to capture the value between on-peak and off-peak pricing periods.

4.7 Comparative Economics

This section examines the various project options by fuel-source and size to determine investment opportunities. An analysis of investment costs, operating (and maintenance) costs, revenues and incentives is included, as well as the overview and results of an economic model of generation options.

4.7.1 Investment Costs

Figure 24 illustrates an electricity project investment model, including both the development phase and the operation phase of a project.

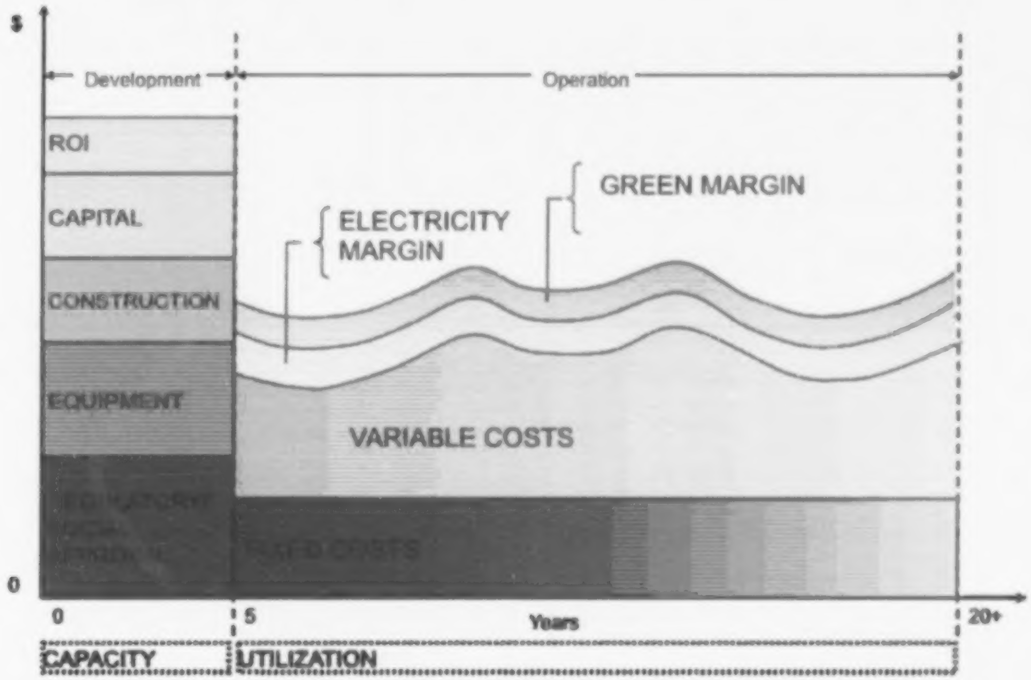


Figure 24: Electricity Project Investment Model

The development phase typically takes 3 to 5 years, depending on the regulatory approvals required and various project risks. The five components to any electrical generation project development are outlined as follows:

1. Regulatory and Social Approval
    - AESO and Alberta Utilities Commission (AUC) processes;
    - Currently approvals take around 2 to 3 years;
2. Equipment
    - Equipment costs and timelines to procure are a function of fuel-type and technology;

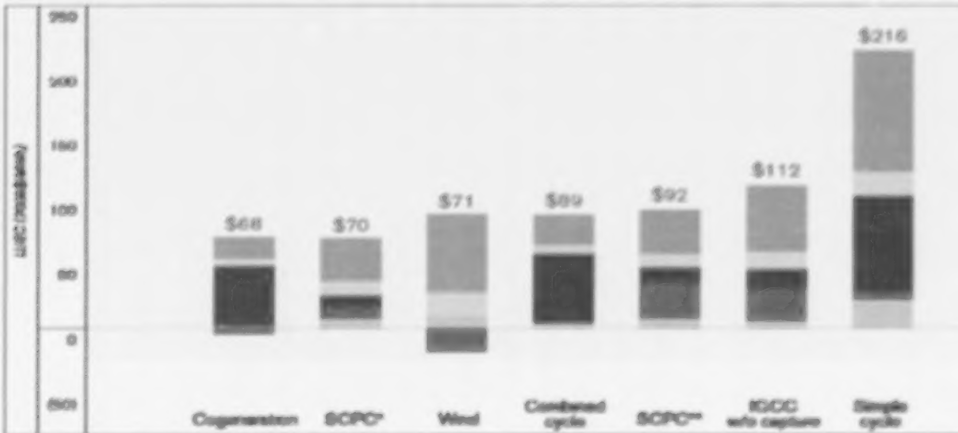
3. Construction
    - Construction costs and timelines to establish contracts and complete the work are a function of both the economy and the project location;
4. Capital costs
    - Capital costs are a function of debt/equity ratios, as well as interest rates and project risks;
5. Return on investment
    - Return on investment is a function of project risks.

The operation phase of an electricity project is typically 20 to 40 years in duration, mostly depending on fuel source and technology type. The four components to electricity project operation are outlined as follows:

1. Fixed costs
    - Includes debt service and overheads;
2. Variable costs
    - Includes fuel costs, operations and maintenance (O&M) costs;
3. Electricity margin
    - Electricity Margin or electricity-related profit is a function of market prices, forward contracts and utilization factor;
    - Electricity revenue can come from both the AESO hourly market and forward contracts;
    - Utilization factor is affected by maintenance outages and possible unscheduled outages;
4. Green margin
    - Green margin is a function of fuel source and the market for carbon offsets and/or Renewable Energy Certificates (RECs).

4.7.2 Operating Costs

Costs to operate generation facilities, typically called Operation and Maintenance (O&M) costs, range from $6 to $19 per MWh, depending on technology type, as illustrated in Figure 25. The graph employs the LUEC methodology for comparing different technologies. LUEC is a means for calculating the cost of a unit of energy. It does this in a manner that allows one form of technology to be compared with another. It includes all the factors that affect the total cost, and views them over a long interval so that end operations such as plant decommissioning can be factored in.



	Cogeneration	SCPC*	Wind	Combined cycle	SCPC**	IGCC w/o capture	Simple cycle
Capital costs	16	33	61	23	34	51	94
O&M costs	6	11	19	7	11	14	19
Fuel costs	47	10	0	53	10	16	74
GHG offset costs	(4)	8	(18)	1	29	24	6
Taxes	2	8	9	4	8	6	23

* In service prior to 2012
** In service after 2012

Numbers may not add due to rounding.

Figure 25: Comparative Levelized Unit Energy Costs (LUEC)

"Simple Cycle" refers to a natural gas-fired generator that essentially burns gas to produce steam and uses the steam to operate a generator. Explanations for the other generation types, including SCPC (Super Critical Pulverized Coal), Natural Gas Combined Cycle, IGCC and Co-generation were provided in Sections 4.1.1 and 4.5.5.

The GHG offset costs in the table are below $0/MWh for Co-generation and wind, because these costs are actually a credit in these instances. It should be noted that the cost of coal as an input fuel is generally stable in Alberta, due to long term contracting for supply. It should also be noted that in a higher priced natural gas environment, other fuel options, including wind, will begin to look much more attractive.

At the low end of the scale, co-generation and natural gas combined cycle projects have operating costs around $6 and $7/MWh, respectively. It should be noted that these projects have higher fuel costs than cheaper coal-fired plants and "free" wind power plants. At the high end, wind and simple cycle gas turbine projects have O&M costs around $19/MWh. It should be noted that O&M costs can vary considerably, depending on labour, maintenance quality, cost of replaceme[illegible]arts, need for servicing, etc.

4.7.3 Revenues

Electricity generator revenue is a function of output of the unit and the market price. The output of a generator depends on the *utilization factor* or the number of hours in a year that the generator is operating at full capacity, when compared to the total hours of the year (8,760 for non-leap years). The utilization factor depends on fuel source (wind, hydro, natural gas, etc.) as well as technology and maintenance requirements. The market price can be either the AESO hourly price or a forward contract price.

Figure 26 illustrates the concept of electricity basis adders – components that add value to the base price for electricity.

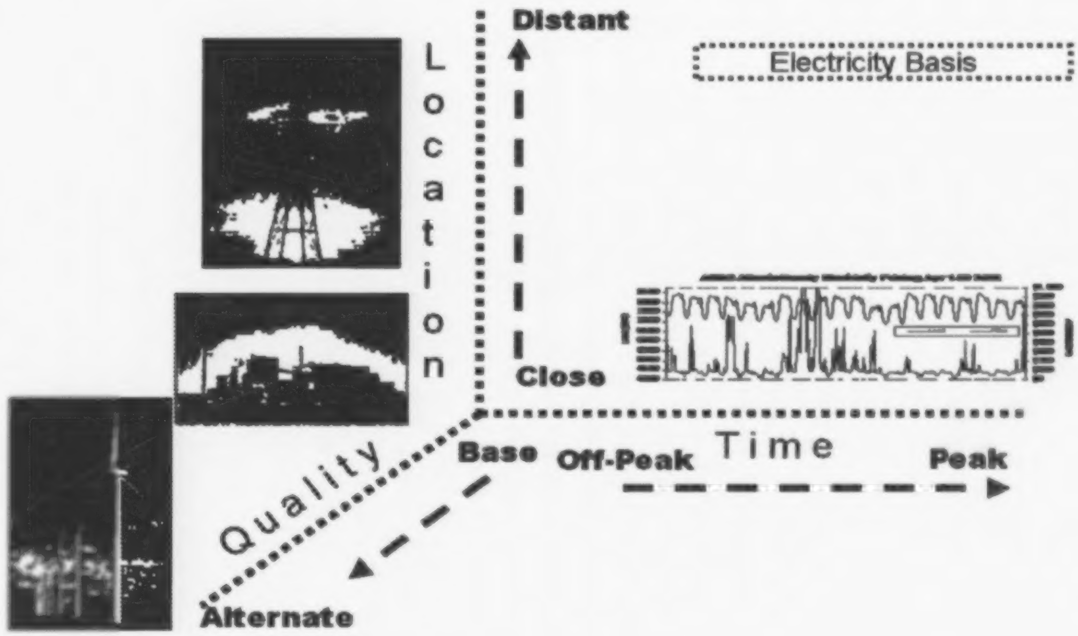


Figure 26: Electricity Basis

The three basis adders are location, quality and time described as follows:

1. Location
   - *Where is the facility relative to demand centres?* If the facility is located close to consumption areas, it is more valuable. If the facility is located far from consumption areas, it is less valuable.
   - Compensation for well-located generation facilities exists in the form of credits for reduced line losses.

   The Northwest Alberta region is particularly lucrative in terms of line loss credits.

   - Generators can earn around an extra 3 or 4% of the AESO hourly price by locating appropriately in the Northwest. By contrast, generators in the Lake Wabamum region actually pay around 5 or 6% of the AESO hourly price in line loss compensation. This line loss difference between the two regions is significant. At a \$60/MWh AESO hourly price, a generator in the Northwest can earn around \$6/MWh than a generator in the Lake Wabamun area. Line loss credits were taken into consideration in the economic modeling – where relevant.
2. Quality
   - *How "clean" or carbon intensive is the electricity?* As a fuel source, coal has an added cost for carbon; whereas wind has added value for carbon offsets.

- *How reliable is the electricity?* Wind power has a lower value because electricity is only generated when the wind blows. This means that the rest of the system will need to compensate when the wind is not blowing.

3. Time
   - *When is the electricity generated?* It is vital to match generation (supply) with demand. Electricity that is generated in higher demand periods has more added value than electricity generated in low demand periods.

The key concern with these value adders is that while the "time" adders are priced in the market, the other adders are not. The carbon aspects of the "quality" adder are sometimes priced, but not often in a market environment. The reliability and location adders are not explicitly priced, despite the general acknowledgement of their value.

Currently, new electricity supply projects located in key areas and with sufficient environmental consideration could earn up to $25-$30/MWh in credits from greenhouse gas (GHG) offsets, line loss savings and other sources if they are designed appropriately.

4.7.4 Incentives

New incentives, or monetary encouragement, are sometimes needed to drive a desired activity. This is particularly true when new technologies are being developed and commercialized, Incentives should represent the "real" value that is not currently being captured. This value can include:

- Renewable value;
- Carbon impact;
- Reliability impact; and/or
- Energy efficiency (line loss reductions).

Various policy instruments can be used as incentives. There are both legislative and non-legislative measures, each of which has a series of sub-categories, as outlined in Figure 27.

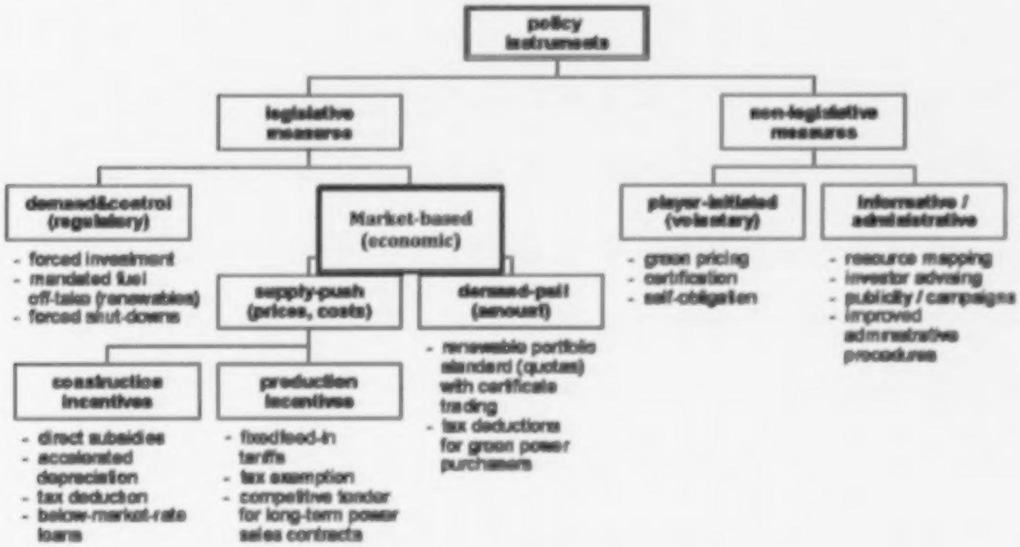


Figure 27: A schematic diagram of policy instruments

Market-based mechanisms are generally preferred over control-based, regulatory measures because they give companies more flexibility to achieve the objectives of the policy.

From a policy-making perspective, choosing the appropriate incentive instrument, and integrating the use of that instrument into a market environment is the key challenge. The policy instruments that are appropriate for the Alberta electricity sector include:

- Non-legislative measures: "player-initiated" and "informative / administrative"; and
- Legislative measures: "market-based (economic)", particularly "demand pull (amount)" measures.

4.7.5 Economic Modeling

Economic modeling was conducted in order to assess the various electricity generation options available to Northern Alberta. RETScreen Clean Energy Project Analysis Software was used to analyze and evaluate various renewable and low-impact energy options according to energy production and savings, costs, emission reductions, financial viability and risk. RETScreen International is managed through the CanmetENERGY research centre of Natural Resources Canada's (NRCan). The modeling was completed for both commercial-scale projects (net exporters to the grid) and micro-scale projects (displacing energy used on site). Specific examples of projects were developed and analyzed.

Commercial-Scale Projects

The following commercial-scale projects were examined using the RETScreen software:

1	Solar Photovoltaic (PV)	0.1 MW (100 kW)	Grande Prairie
2	Wind	50 MW	Peace River
3	Wind	50 MW	Cold Lake
4	Natural Gas Combined Cycle	300 MW	Fort McMurray
5	Landfill Gas	3 MW	Grande Prairie
6	Biogas	0.1 MW (100 kW)	High Level
7	Geothermal	60 MW	Grande Cache
8	"Micro-hydro"	0.35 MW (350 kW)	Slave Lake

Table 22: Commercial-Scale Model Projects

Please note that the Solar PV (#1), the Biogas (#6) and the "Micro-hydro" (#8) projects are included as Commercial projects because the analysis presumes the total output would be sold the grid. Micro-generation projects in Alberta have to have generation capacity that is less than 1 MW and is roughly equal to the power consumed on-site. The model assumed all output was available for sale. The three technologies and the project sizes would qualify them as micro-projects in Alberta so long as the consumption for the customer was at the sized level.

Micro-Scale Projects

The RETScreen software was also used to review the following micro-generation options:

1	Solar Photovoltaic (PV)	0.4 kW	Fairview, Off-grid
2	Micro-wind	1 kW	Slave Lake, Off-grid

Table 23: Micro-scale Model Projects

In order to compare the various fuel/technology options and determine the optimal electricity options, several key assumptions were made in the modeling, as listed below.

Key Assumptions:

- 2.0% inflation rate;
- Debt interest rate (long-term borrowing rate, after tax):
  - The length of the borrowing term varies according to the lifecycle of the project equipment and overall size of the project;
  - Shorter-term, smaller projects are given a 5.5% rate for 10 years; and
  - Longer-term, larger projects are given a 6.5% rate for 20 years.
- Greenhouse gas offset revenue of $15 / tonne (subject to inflation at 2%);
- Electricity prices:
  - Long-term pricing was set at $ 80.00/MWh. By comparison, the average price in 2008 was approximately $90.00/MWh. While the current 5-year forward curve is less than $60/MWh, it is acknowledged by industry that this pricing level is insufficient to induce new generation build. It is expected that over the longer term, the price of electricity will rise.

- Wind is priced at 85% of the long-term price. This is because many wind projects produce electricity at the same time (when the wind is blowing), which increases (price-taking) supply and reduces the average price. Typically, wind has been receiving around 80% of the average price; however, wind in the north does not blow at the same time as wind in the south, hence 85% was used instead of 80%.
- Average electricity price varies each month, due to supply and demand conditions. The following price variability was applied to the modeling:

[redacted]		
January	$100.00	$85.00
February	$100.00	$85.00
March	$75.00	$63.75
April	$55.00	$46.75
May	$50.00	$42.50
June	$50.00	$42.50
July	$95.00	$80.75
August	$90.00	$76.50
September	$60.00	$51.00
October	$90.00	$76.50
November	$95.00	$80.75
December	$100.00	$85.00

Table 24: Model Pricing and Wind Pricing by Month

- This seasonal pricing is illustrated graphically in Figure 28 below:

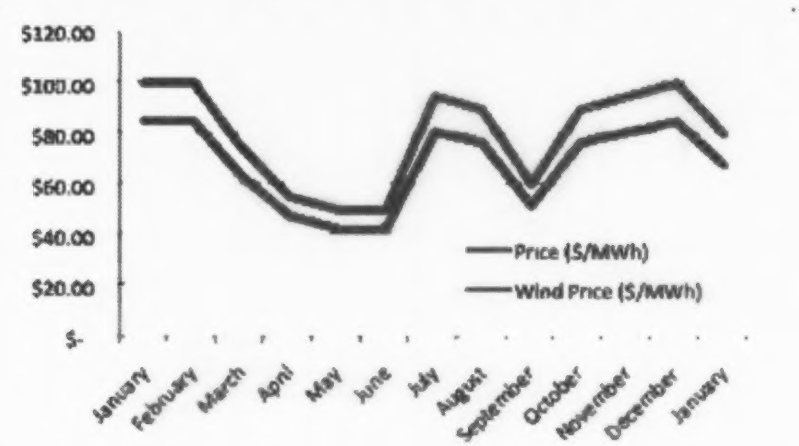


Figure 28: Model Pricing and Wind Pricing by Month

- The varying monthly pricing is only used for fuels with varying seasonal output including wind and solar PV. The model does not use varying pricing for baseload units such as natural gas combined cycle, landfill gas, biomass and geothermal.

4.7.6 Model Results

Table 25 outlines the results of the model by project:

	NADC Economic Analysis Summary					Results					
Projects Analyzed											
Commercial	Fuel Type	Location	Size	Capital ($'000)	Operating ($'000)	Return ($'000)	NPV (10%) ($'000)	B/C Ratio	NPV/MW ($'000)	Marginal ($/MWh)	Payback (years)
1	**Solar Photovoltaic**	**Grande Prairie**	**100 kW**	**$ 961**	**$ 79**	**Neg**	**-$780**	**-1.71**	**-$7,800**	**$566.12**	**362.8**
2	Wind	Peace River	50 MW	$105,166	$ 8,055	10.2%	$548	1.02	$11.0	$ 71.00	11.9
3	**Wind**	**Cold Lake**	**50 MW**	**$105,166**	**$ 7,862**	**5.0%**	**-$17,575**	**0.44**	**-$351.5**	**$ 88.74**	**16.0**
4	Natural Gas Combined	Fort McMurray	300 MW	$427,988	$155,905	65.1%	$607,335	5.73	$2,024.5	$ 54.74	4.0
5	**Landfill Gas**	**Grande Prairie**	**3.0 MW**	**$ 10,513**	**$ 2,643**	**67.9%**	**$ 19,653**	**7.23**	**$6,551.0**	**$ 2.24**	**3.5**
6	Biogas	High Level	100 kW	$ 473	$ 65	21.9%	$ 235	2.66	$2,350.0	$ 53.89	7.4
7	**Geothermal**	**Grande Cache**	**60 MW**	**$235,422**	**$ 26,150**	**38.7%**	**$221,609**	**4.14**	**$3,693.5**	**$ 39.97**	**5.9**
8	Micro-hydro	Slave Lake	350 kW	$ 2,392	$ 242	7.3%	-$185	0.74	-$528.6	$ 86.40	13.1
Micro- Scale	Fuel Type	Location	Size	Capital ($'000)	Operating ($'000)	Return ($'000)	NPV ($'000)	B/C Ratio	NPV/kW ($'000)	$/MWh	Payback (years)
1	**Solar Photovoltaic**	**Fairview, Off-grid**	**0.4 kW**	**$ 5.8**	**$ 0.6**	**Neg**	**-$4.1**	**-1.37**	**-$10.3**	**NA**	**61.9**
2	Micro-wind	Slave Lake, Off-grid	1 kW	$ 5.5	$ 0.4	16.30%	$ 2.7	1.5	$ 2.7	NA	6.6

Table 25: Economic Model Results

Detailed model results are available in Appendix 4.

The model inputsand result explanations are as follows:

- Eight commercial and two off-grid micro-generation projects were analyzed using the Natural Resources Canada (NRCan) RETscreen software designed for green energy projects in Canada;
- The *Fuel Type* and *Location* selections were intended to give a cross section of potential for the projects in Northern Alberta;
- The RETscreen software provides standard meteorological data for selected Alberta locations and these were used to assist in locating the various projects;
- The project *Size* was based on the RETscreen software and adjusted in some instances for location factors relative to the selected project site;
- The *Capital* and annual *Operating* costs were based on the average costs for supply of equipment and construction of the facilities, with no extra allowances for location;
- The *Return* column is the internal rate of return generated for the project on a pre-tax basis and provides a comparative measure of a projects value, with no adjustments for any risk differences between the projects;
- The discount factor for the net present value (NPV) calculation was set at 10% for all ten projects analyzed. This allows a relative comparison of the NPV/MW of capacity for the ten projects;
- The benefit /cost (B/C) ratio also uses the 10% discount factor and provides a multiple of the discounted revenues as a ratio to the cost to build;
- The absolute value for the projects would vary if the discount factor were greater or less than the 10% factor; however, the relative comparisons would remain consistent;
- The *Payback* in years is based on un-discounted cash flows.

Location and Carbon Offset Credits

All of the projects use the $15.00/tonne value for CO_2 offsets, escalated at an annual rate of 2% per year and offset at a rate of 0.847 tonnes/MWh of output. Note this is a slight decline from the 2008 value of 0.88 tonnes (discussed in section 4.4.2) as a result of new natural gas and wind additions to the grid over the past two years.

The RETScreen model does not have a specific variable to adjust for location credits. However, a sensitivity test was applied to the Peace River wind project (#2) by converting a 5% 'other losses' factor to a 2% credit or a total of a 7% adjustment. The net effect of this adjustment is:

- An increase in the IRR for the project from 10.2% to 12.6%;
- An increase in NPV from $548,000 to $8,200,000;
- An increase in NPV per MW from $11,000 to $164,000;
- A reduction in marginal production costs from $71/MWh to $60/MWh; and
- A shortening of the payback period from 11.9 years to 11 years.

The net effect is similar to a price increase from the $66.30/MWh used by the model to $71.00/MWh. The results could be considered significant with respect to the viability of this project, and would have similar impacts on all other projects in Northern Alberta that could earn location credits. It should be noted that these would not likely be available at any locations that are already surplus generating points such as Fort McMurray, Cold Lake, and Grand Cache.

Model Observations

The following key observations can be made with respect to the analysis of these hypothetical projects:

- ***Solar PV*** is not viable, either commercially or as a micro-generation project due to the limited sun in the winter and the high capital costs;
- ***Wind power*** is marginal, on the edge of being economic, depending on the location and wind regime:
    - Two commercial projects were examined, in Peace River and in Cold Lake. The wind regime in the Northwest is better than the Northeast resulting in a 10% internal rate of return (IRR) for Peace River and 5% IRR for Cold Lake;
- ***Natural gas combined cycle*** has a very high IRR at $6.00/GJ natural gas and $80/MWh electricity prices. This is the best option for generation from a purely financial perspective;
- ***Landfill gas*** and ***biogas*** are both economic, but are small-scale projects.
    - Landfill gas benefits from the high value of methane destruction in terms of offset credits.
- ***Geothermal*** project economics are positive; however, they are dependent on accessing high temperatures for steam generation. As discussed in the geothermal section of this report, this is very much an unknown factor for Northern Alberta;
- ***Small-scale hydro*** and ***small-scale wind power*** may be marginally economic for isolated generation locations as offsets to higher cost alternatives, such as diesel-fired generation.

Use of Micro-generation by Municipalities:

The main issue for municipalities looking to build micro-generation to match their consumption is that the consumption occurs at different locations with different metering points. Under the current rules, the consumption from these different points cannot be aggregated and used to match the capacity of the micro-generator. A change to the AUC rules may allow municipalities to become more engaged in micro-generation projects.

SECTION SUMMARY:

Electricity generation investment costs, operating costs, revenues and possible incentive schemes need to be considered when determining whether projects are viable. A RETScreen analysis was conducted to examine Northern Alberta's generation options.

The most viable generation option for Northern Alberta is natural gas combined cycle in the Fort McMurray area. Commercial-scale wind power is marginally-economic, and better off in the Northwest, due to a stronger wind regime. Landfill gas and biogas projects could also be developed economically on a small-scale.

In terms of micro-generation projects, both small-scale wind power and hydro could be developed in isolated areas with no access to the power grid, and only expensive alternatives available to the area. Otherwise, these projects will be too costly.

5. Challenges to Development

This section examines some of the policy, market, regulatory, technical and economic challenges to developing new electricity generation projects in Northern Alberta.

5.1 Policy Challenges

From a policy perspective, there are several key challenges to electricity project development, including:

- ***The electricity generation sector has been deregulated, relying entirely on the private sector:***
  - All new generation projects need to be commercial. This makes it difficult to use government policy as a tool to stimulate investments, particularly in renewables. Any changes to the current system will change the economic environment for those who have made generation investments in good faith;
  - This does not mean that the government should be subsidizing generation, but that the government should set appropriate policy in place for new, renewable investors to capture value associated with line losses and carbon credits.

- ***Regional Transmission development is delayed:***
  - Most Northern Alberta generation projects will require transmission upgrades. Outside of current "Bill 50" plans, nothing is being scheduled. The focus of new transmission build will be on the very large projects for the next 5 to 7 years. These large projects will consume the majority of the engineering and construction resources, leaving little left for regional projects;
  - If competitive procurement and appropriate project milestones are used for all transmission projects, it may be possible to ensure regional transmission is being developed as needed alongside larger projects;
  - Policy also needs to be directed to streamlining and simplifying the connection process for grid connections. Currently the AESO, AUC, and Transmission and Distribution Facility Owner processes can take as long as 3 years from project inception to actual connection.

- ***Distributed Generation policy is ineffective:***
  - Government policy for small, distribution-connected projects should enable these generators to sell their electricity back to the distributors, and acquire line loss credits and carbon offset value;
  - An appropriately designed net billing structure as opposed to the current net metering system in Alberta would enable this;
  - Policy should be directed to projects that are greater than 1 MW and less than 50 MW (intermediate-scale) to develop new regulations and connection procedures for renewable projects within this range.

5.2 Market Challenges

There are several challenges to project development that exist because of the current market structure. This is not to say that massive market structure changes are needed immediately, but that these challenges must be recognized in order to develop appropriate policy for overcoming them. Market challenges include the following:

- ***The current structure is an "energy-only" market with no capacity payments to generators:***
    - Generators are paid for their output, (electricity), on an hourly basis and do not receive other *out-of-market* compensation such as payments for their available capacity. A large number of North American de-regulated energy markets employ capacity markets to compensate for revenue shortfalls from the hourly price;
    - The result is that developers and investors prefer the certainty of these markets to the relative uncertainty in the Alberta market. Most investments in Alberta generation over the past ten years are from co-generation with a need for steam for industrial purposes, from wind projects selling renewable credits and from new coal developments replacing existing assets;
    - The key obstacle with this market structure is the inability to obtain risk related returns on capital. The market structure tends to suppress the price during periods of high wind power production. This leads to the expression "wind eats its own lunch," meaning that the more wind generation on the system, the lower the price becomes;
    - High prices in the current market are not predictable, meaning that investments cannot be aimed at high price capture;
    - The market does not recognize value adders such as generation located in supply deficit areas and the benefit of cleaner, renewable fuels.

- ***Volatile short-term pricing:***
    - Market volatility driven by unpredictable factors such as unscheduled outages and wind generation coming on- and off-line. This makes it difficult to capture value and make investments targeted at high-priced hours;

- ***Longer-term price is a function of natural gas prices:***
    - The long-term price of natural gas is going to be upper limit on long-term alternative investments in electricity. Current gas prices at $4.75 to $6.00/GJ will leave the electricity market below $60 to $65 per MWh;

- ***Government policy on the structure of the electricity market is subject to change:***
    - There is a concern that the government may intervene in the market if new generation is not built in a timely manner. The move by the government to ensure new transmission is built by changing the traditional regulatory process has created uncertainty with respect to generation development;

  - The recent financial support for the Carbon Capture and Storage project provided to TransAlta and Capital Power at the Keephills coal project is perceived by other generators as resulting in an un-even playing field for future investments in renewable or low carbon output generation;
  - Alberta Energy announced on March 26, 2010 that the AUC would review Regulatory processes specifically for hydro development in Alberta, an action that could be interpreted as favouring one technology over others;
  - This uncertainty in the potential for government intervention will affect investor confidence in investing in projects that may be adversely affected by changes in policy or in the government backing selected technologies or fuel types;

- ***There is limited value for carbon offsets and Renewable Energy Certificates (RECs):***
  - Carbon offsets are currently priced through government policy, not a robust carbon market;
  - There is no compliance market for RECs, all of the trading is voluntary at this point;
  - The REC market is not based on local demand and supply conditions, but is based on pricing in US jurisdictions.

5.3 Regulatory Challenges

There are three key regulatory challenges to project development:

- The ***grid connection process*** is onerous and lengthy:
  - The process is overly complex and difficult to navigate for both commercial-scale and micro-generation projects;
  - The current grid connection process is some 40 months from project initiation to connection and the AESO has an objective to reduce this to 25 months through a revision to its current procedures;
  - These changes will benefit larger scale projects (>50 MW), however may make the process for intermediate size projects lengthier and more expensive;

- The micro-generation policy is ***too restrictive***
  - Micro-generation applies only to projects <1 MW and for netting against on-site consumption. The policy actually restricts the size of the projects to no greater than the on-site peak usage;
  - The benefit of on-site generation is only the off-set of energy consumed with no value capture for added benefits of renewable and line loss reductions;
  - Micro-generation projects are at-risk to the distributor's connection process. This is made more complicated in that some distributors often view micro-generation projects as possible compromises to system reliability, and may not be supportive of their development.

- There is ***no short-term grid connection process option*** for intermediate scale projects akin to the AUC process developed for micro-projects that would facilitate development of local generation:

- Most distribution companies, with exception of ENMAX, are not promoting distributed generation, and are not making efforts to simplify grid connection for smaller projects.

5.4 Technical Challenges

There are three types of technical challenges to generation development in Northern Alberta, outlined as follows:

- ***Resource / Fuel*** challenges:
  - There are limited hydro resources available, and most are not located close to transmission lines;
  - There is not enough sun, particularly in the winter months (peak demand period) for solar PV projects to be cost effective; and
  - Some areas of Northern Alberta, particularly in the Northeast, do not have enough wind to make wind power generation economic.

- ***Technology*** challenges:
  - The only mature option for electricity storage is pumped storage using hydro facilities. However, project economics for pumped storage projects in Alberta are compromised by the AESO hourly price structure and its inherent uncertainty and volatility. Other storage options are not yet mature enough, from a technology and cost perspective, to be useful.
  - The development of geothermal resources does offer some interesting potential for Alberta given Alberta's expertise in drilling technologies.
  - The Swan Hills in-situ coal gasification project has demonstrated some attractive results in use of deep underground drilling and access to fuel sources and with reduced carbon impacts;
  - The geothermal electricity production technology is not yet sufficiently mature to deliver economic results; however more research into the geothermal options should be considered.

- ***Distributed Generation*** (the use of small-scale micro-generation units, instead of large-scale, centralized power plants). challenges include:
  - There are no uniform interconnection standards addressing safety, power quality and reliability for small, distributed generation systems.
  - The interconnection process generally involves communication and applications with many different entities, instead of a "*one-stop shop*" for applications.
  - The environmental regulations and permit process that have been developed for larger projects and make some smaller distributed generation projects uneconomic.
  - Many contractual challenges exist for projects, including:
    - Liability insurance requirements;
    - Fees and charges; and
    - Extensive paperwork.

5.5 Economic Challenges

There are two main economic challenges to electricity generation development in Northern Alberta, outlined as follows:

- *Capital acquisition*:
  - Banks do not like to finance projects with uncertain revenue streams and risks of policy intervention. As such, it is generally difficult to raise equity capital. Electricity projects must compete for capital against other energy development projects in Alberta.
  - The only electricity generation projects with high IRRs are cogeneration projects. All other generators will have more difficulty financing their projects.
  - Other jurisdictions are providing renewable generators with more certainty and less risk with regards to the application environment and revenue stream. Several European jurisdictions and the Province of Ontario use feed-in-tariffs to guarantee revenue for long time periods to renewable generators.
  - Some projects, such as landfill gas, may have additional environmental and regulatory requirements which could result in project uncertainty and a challenge to capital acquisition.

- *Inability to capture value-add benefits*:
  - Small-scale generation projects are not able to easily capture location credits (such as line loss credits) and carbon offsets. These value adders would often turn marginal projects into profitable opportunities
  - Constraints to micro-projects such as net metering, restrictions in size to peak consumption, and lengthy siting processes for small scale, non-micro projects result in added costs and uncertain project economics..

SECTION SUMMARY:

There are several policy, market, regulatory, technical and economic challenges inhibiting the development of new generation projects in Northern Alberta. Key challenges include:

- Regional transmission development is delayed, which will result in difficulties connecting generation projects to the grid in Northern Alberta;
- The current market structure does not allow renewable projects sufficient price certainty to acquire project investment and financing;
- The grid connection process, particularly for smaller projects, is too complex and onerous;
- There is not enough sun, and sometimes not enough wind or accessible hydro resources to develop certain renewable projects; geothermal technology is not mature enough to warrant commercial investment;
- There are difficulties with capital acquisition due to the risks associated with investment, returns and timing of new generation projects; and
- There is an inability to capture value-add benefits (such as location credits and carbon offsets) in Alberta.

6. Next Steps

While there are many measures that can be recommended in order to enhance electricity options for Northern Alberta, this section focuses on a few key areas that could bring viable opportunities through very specific, strategic measures.

These recommendations focus on the policy, market and regulatory areas, as these areas are the most promising targets for short-term change. It is anticipated that these recommendations may develop into discussions with industry participants, and ultimately with government and the agencies responsible for implementation.

6.1 Recommendations for Policy Development

Policy must enable communities and businesses the opportunity to develop generation projects that have inherent social and economic value. While policy can be put in place to facilitate the development process, it is anticipated that these projects would still be subject to existing processes and market rules.

From a policy perspective, consideration needs to be given to developing programs that recognize value adders (location, renewable), particularly for projects that are larger than micro-generation (i.e. greater than 1 MW) and smaller than 50 MW. This range of projects cannot take advantage of any micro-generation connection initiatives and cannot currently compete with bigger generation projects.

Developers of large scale projects generally have the time, resources and expertise to manage the inter-connection processes and to finance their projects as elements of an overall portfolio. These portfolios can be either other generating assets, or elements of an industrial process such as bitumen recovery.

The "value adders" in question include:

- Location Credits:
  - Such as line loss credits and transmission build / congestion management offsets for locating generation in a supply deficit area.
- Carbon Offsets:
  - Developing a carbon accounting standard for clean energy projects; and
  - Facilitating a carbon-value capture by defining their respective off-set values

It would be important to work with the AESO to develop the location credits value adder, and with the exchange and broker community to develop the carbon offsets accounting and value infrastructure.

Projects in the ***intermediate range*** (1 MW to 50 MW) with capital requirements varying from $1,000,000 to $100,000,000 are left to compete for regulatory, engineering, and financial resources against the larger scale projects that have been prevalent in Alberta's generation development since de-regulation.

6.2 Recommendations for Market Development

As highlighted in Section 4.7.4, markets are inherently more efficient than regulations in that they reward, rather than penalize, innovation. Markets-based solutions should be used to facilitate the electricity project development process.

From a market perspective, it is important to provide some investment certainty, particularly for intermediate scale generation projects. This can be achieved, without providing subsidies, by creating market products that smaller-scale generation can sell with relative certainty.

Most intermediate-scale renewable projects cannot compete in the current market structure. They would be submitting zero dollar offers into the AESO hourly market, bringing no guaranteed revenue stream. Without a consistent revenue stream, it is very difficult to finance a project.

The solution to this dilemma is to encourage a forward market for ***"bulk energy"*** products. Essentially, a product that relates to the total volume (MWh) produced by a renewable project, not directly related to when the electricity is produced. This bulk energy could be sold at periodic auctions and other market players could "firm it up" (make it less intermittent, more like baseload power) by using natural gas-fired generation and demand response to build a portfolio of firm electricity.

The development of a bulk energy product would enable renewable developers to stick to developing and operating renewable energy facilities. The marketing and sales responsibilities would be transferred to other market participants who have large enough portfolios to address the intermittent nature of the electricity.

6.3 Recommendations for Regulatory Development

Regulatory processes need to be streamlined to enable new electricity generation projects to be developed and implemented in a timely manner. A well-developed application process should allow for a single application that covers all affected entities (the Alberta Utilities Commission, the AESO, distributors and transmission companies).

From a regulatory perspective, the lack of process streamlining has a disproportionately penalizing effect on micro-generation and small-scale projects. If there is one key project that should be improved upon, it is ***the streamlining of the regulatory process for micro-generation and intermediate-scale renewable projects***. In the current environment, very small generation projects still have to jump through regulatory hurdles when it comes to developing, connecting and operating their facilities.

There are a series of distributor approvals that are required in order for these projects to be built, and as discussed in Section 5.3, there are times when the distributor sees a micro-generation project as a risk and is not willing to facilitate its development. A regulatory review of the connection, development and operation requirements for micro-generation and intermediate-scale renewable projects should be conducted with the aim of simplifying the process.

SECTION SUMMARY:

The following specific and strategic recommendations will allow for more electricity project development activity in Northern Alberta:

1. Develop programs that recognize value adders such as location credits (for locating generation projects in areas of need) and carbon offsets (for clean, renewable generation projects).

2. Develop forward contracting market for intermediate-scale renewable generators. This may include the development of long-term power purchase arrangements that include energy and renewable offsets, as well as consideration for "bulk energy" products that would allow intermittent, renewable generators to sell a volume of electricity, irrespective of the time of day the electricity is produced. Natural gas generation and *demand response* could be used to "firm up" this intermittent generation

3. Streamline the regulatory process for micro-generation and intermediate- scale renewable project development, grid connection and operation. Currently there are no specific regulatory processes that target commercial generation projects less than 50 MW. As such these projects get entangled in the lengthy processes with load and larger generation connections that can take as long as 3 to 3.5 years from initiation to connection

APPENDIX 1: AESO Hourly Market – 2008 to 2009

This is a continuation of the discussion in Section 2.1.2. Figure 29 illustrates a load and price duration curve for 2007.

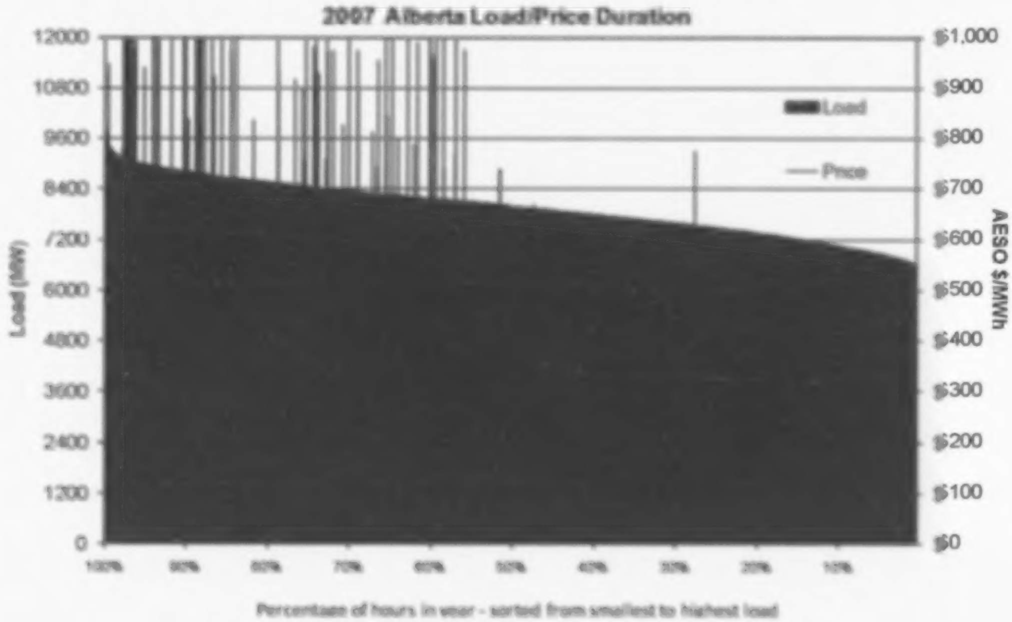


Figure 29: 2007 Load and Price Duration Curves

Of particular note is the dispersion of high prices across a broad range of hours and loads. Unlike many jurisdictions where the high prices generally coincide with peak demand, the Alberta market has the potential for high prices across nearly all the hours. This uncertainty in prices is causing concerns for the level of reliable and dispatchable generation and has led to concerns with the growth in wind-based generation that is neither dispatchable nor reliable.

In Figure 29 the extremely high prices (>$200/MWh) cover 50% of the hours of the year in terms of higher load levels. Figure 30 is a load and price duration curve for the AESO market in 2008. In this case, the extremely high prices cover 80% of the higher load hours of the year. It becomes transparent that high price levels in Alberta do not necessarily correspond to high load levels, and hourly price volatility increased between 2007 and 2008.

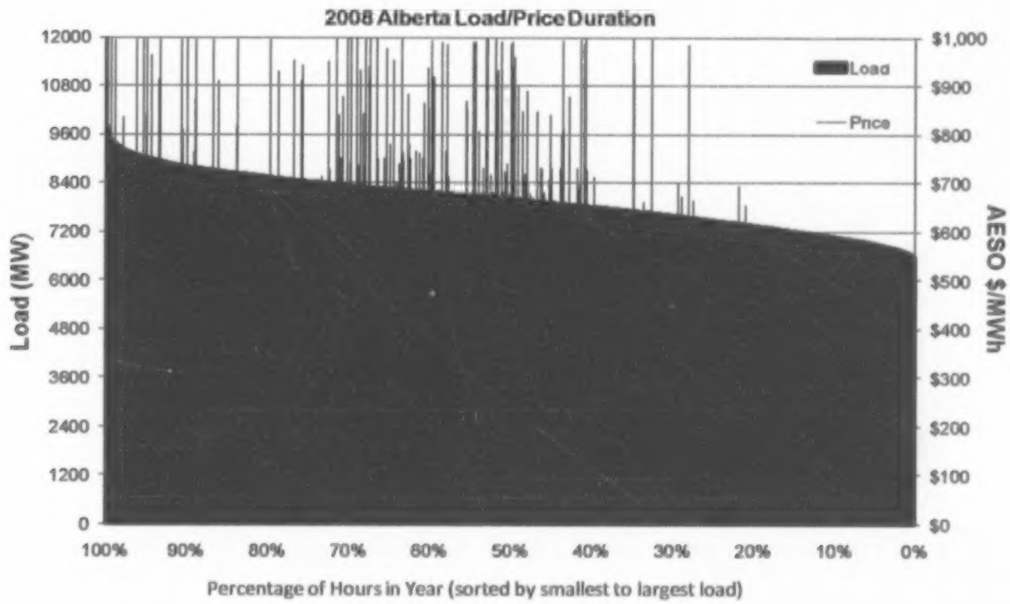


Figure 30: 2008 Load and Price Duration Curves

The 2009 load and price duration curve (Figure 31 below) indicates the continued lack of correlation for last year, however at much lower price levels. Over the three years the average price moved from $66.95/MWh in 2007 up to $89.93/MWh in 2008 and back down to $47.81/MWh in 2010.

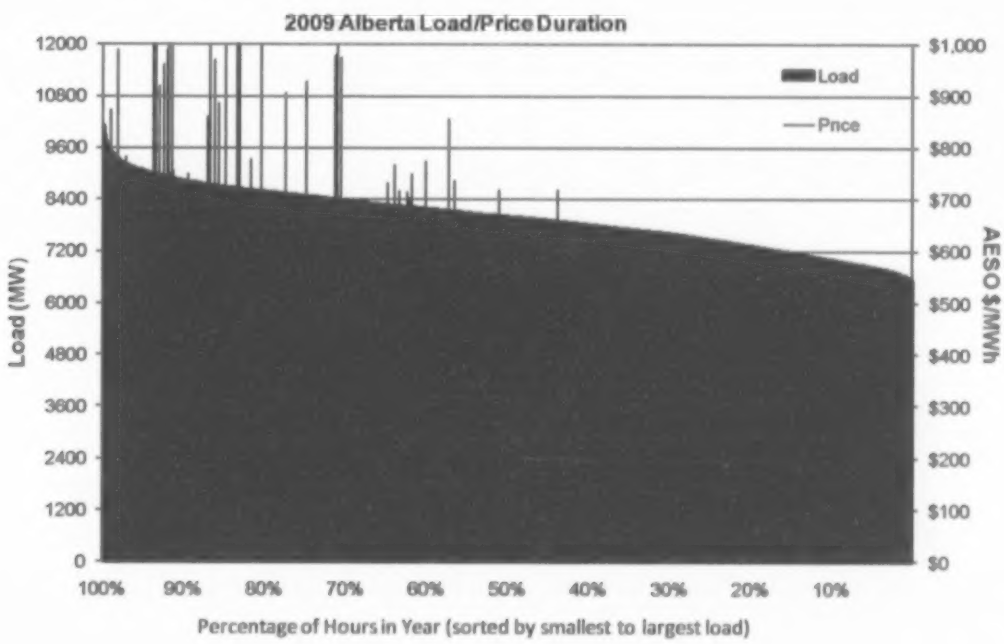
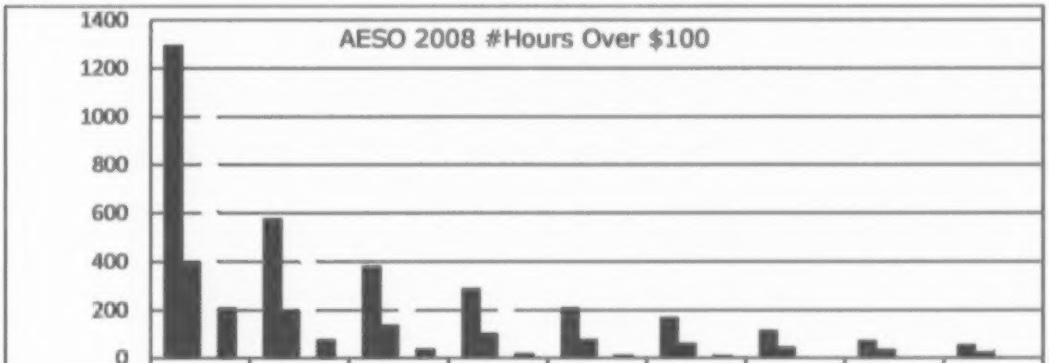


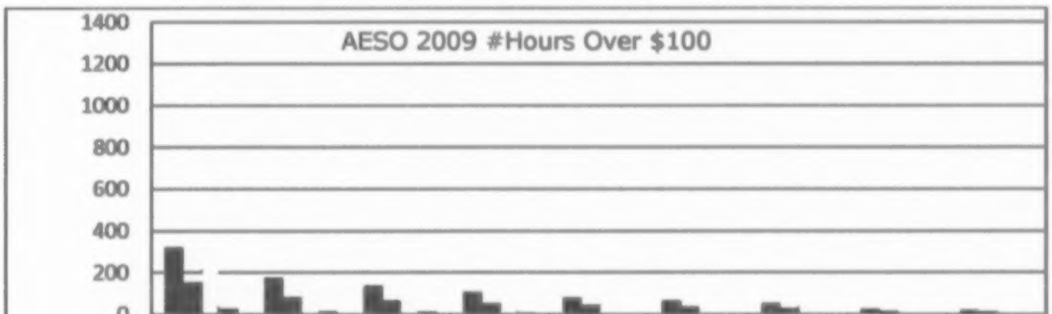
Figure 31: 2009 Load and Price Duration Curves

Figure 32 highlights the number of hours with prices over $100 increments in 2008 and Figure 33 has comparable data for 2009. These numbers are also broken out by time period as follows: Super Peak (5:00PM to 10:00PM, seven days per week), Peak (8:00AM to 11:00PM, 7 days per week, which includes the Super Peak timeframe), and Off Peak (11:00PM to 8:00AM, seven days per week).



	$100	$200	$300	$400	$500	$600	$700	$800	$900
All Hours	1297	579	381	289	209	169	117	73	55
Super Peak	393	193	140	105	79	63	47	36	25
Peak	1088	501	342	269	195	159	112	71	53
Off Peak	209	78	39	20	14	10	5	2	2

Figure 32: Number of hours priced at over $100 increments in 2008



	$100	$200	$300	$400	$500	$600	$700	$800	$900
All Hours	322	176	138	106	80	65	52	25	20
Super Peak	152	82	66	52	44	36	27	15	11
7X16 Peak	295	161	126	100	76	61	48	23	19
Off Peak	27	15	12	6	4	4	4	2	1

Figure 33: Number of hours price> $100 in 2009

In both years it is apparent that the Super Peak timeframe does not include all of the highest priced hours, and in fact some of these hours occur during Off Peak times when demand is expected to be low. The incidence of price excursions over $100 also declined dramatically from 2008 to 2009 dropping from 1297 hours (14.8%) to just 322 hours (3.7%) in 2009.

Figure 34 illustrates the number of hours with prices over $100 by season, for 2008 with comparable data in Figure 35 for 2009. This graph highlights that the expected seasonal correlation does not hold true. Alberta is generally described as a winter-peaking jurisdiction; however in 2008 there are more high priced hours in the summer than in the winter.

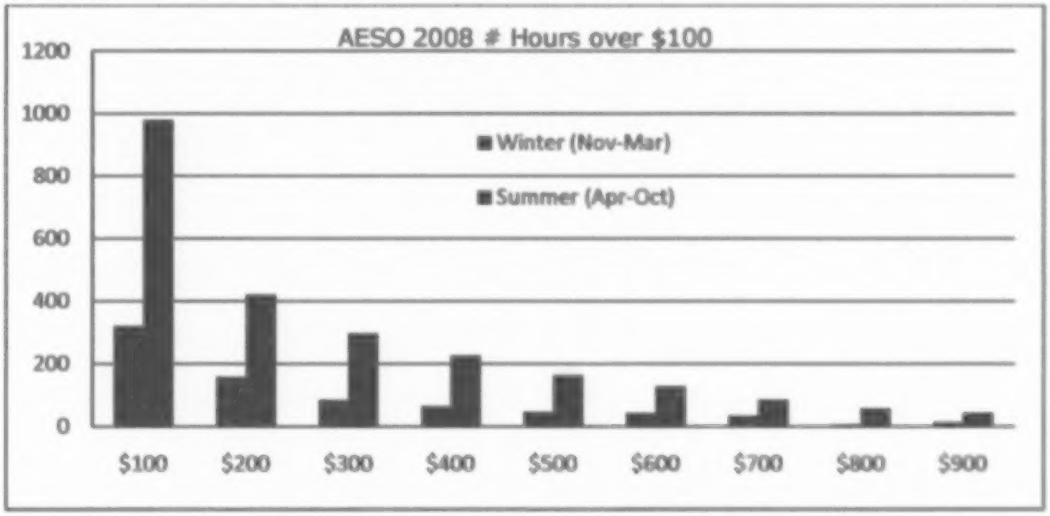


Figure 34: Number of hours priced at over $100 increments in 2008, by season

In 2009 the number of winter hours over $100 is nearly the same as 2008, however the summer peaking hours dropped from nearly 1000 hours to less than 130 hours.

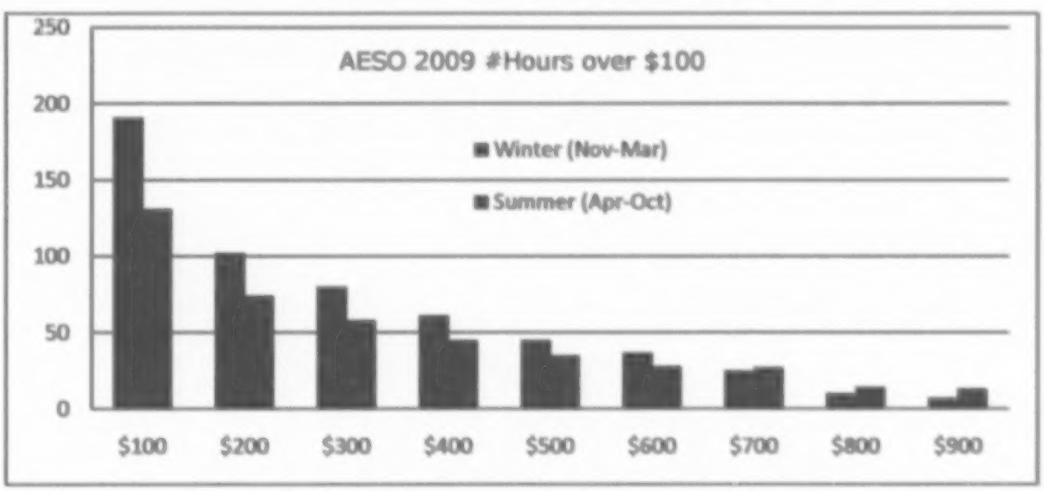


Figure 35: Number of hours AESO hourly price >$100 in 2009, by season

Figure 36 illustrates the number of hours priced at over $200 by hour of the day in 2008 again with comparable 2009 date in Figure 37. It would have been expected for the Super Peak hours (HE 17 to HE 23) to have the greater instances of high prices; however, the greatest instance of high prices actually occurs in HE 12, followed by HE 13 and HE 14 in 2008. In 2009, the peak hours are the winter hours from 5:00PM to 7:00PM but with a much lower incidence than 2008.

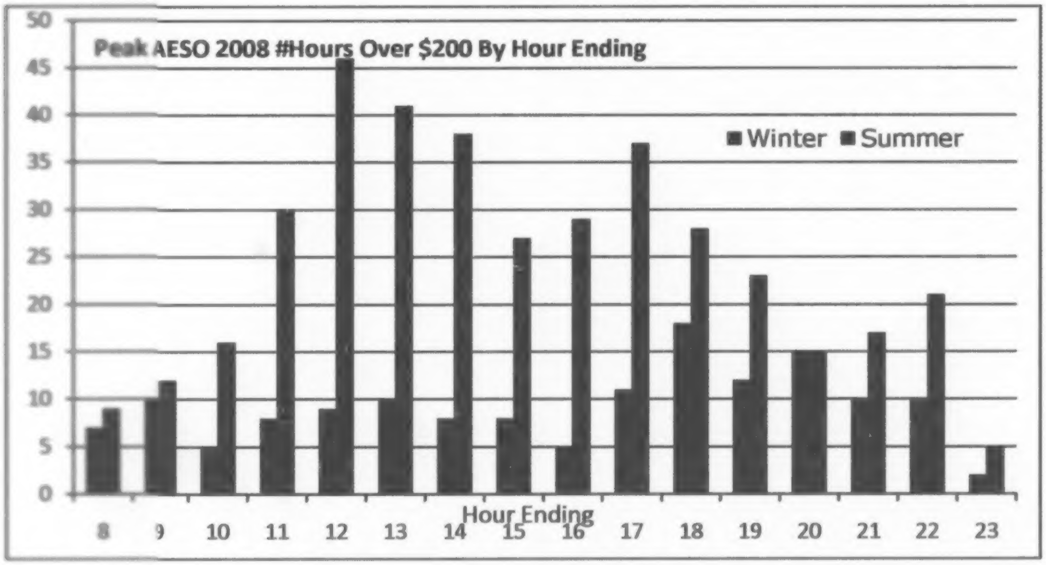


Figure 36: Number of hours priced at over $200 in 2008, by hour of the day

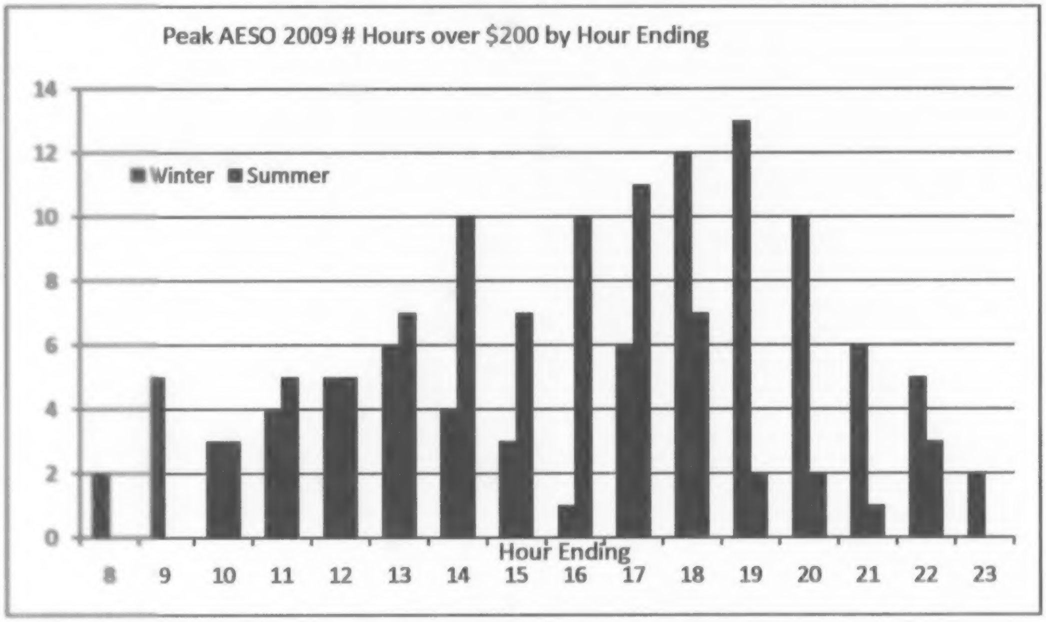


Figure 37: Peak Hours> $200 by hour of day

Figure 38 illustrates the number of hours priced at over $200 by day of the week in 2008. The expected result would be to have the high price instances greater during the weekdays than on the weekend, and this expectation holds true for the summer. However, during the winter, Saturday and Sunday both have higher instances of high prices than Wednesday, Thursday and Friday.

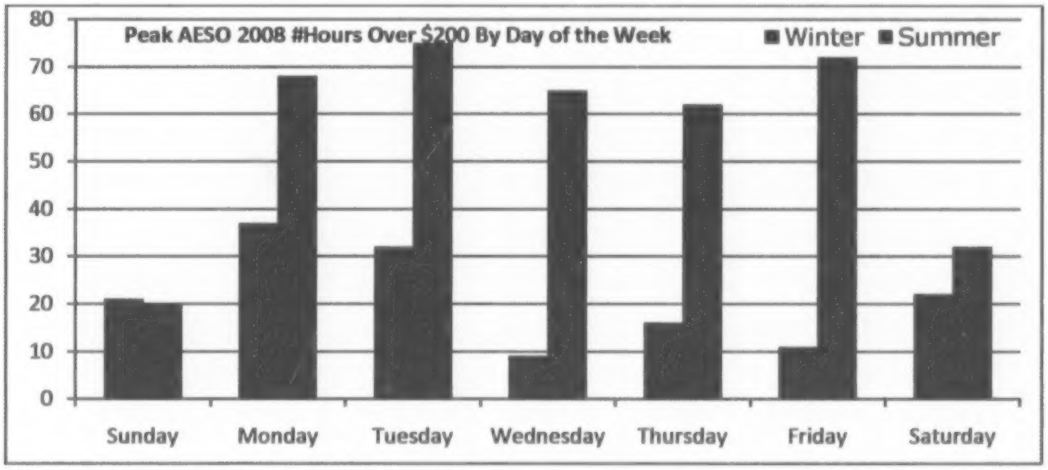


Figure 38: Number of hours priced at over $200 in 2008, by day of the week

Figure 39 provides comparable data for 2009 with the winter peak price occurring on Wednesdays and no price excursions on Mondays in the summer.

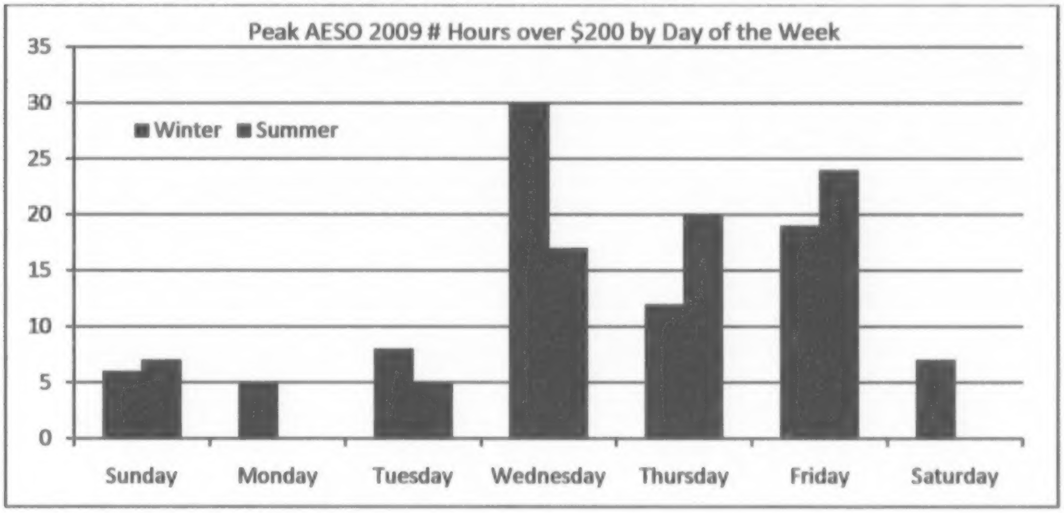


Figure 39: Peak Hours > $200 in 2009, by day of week

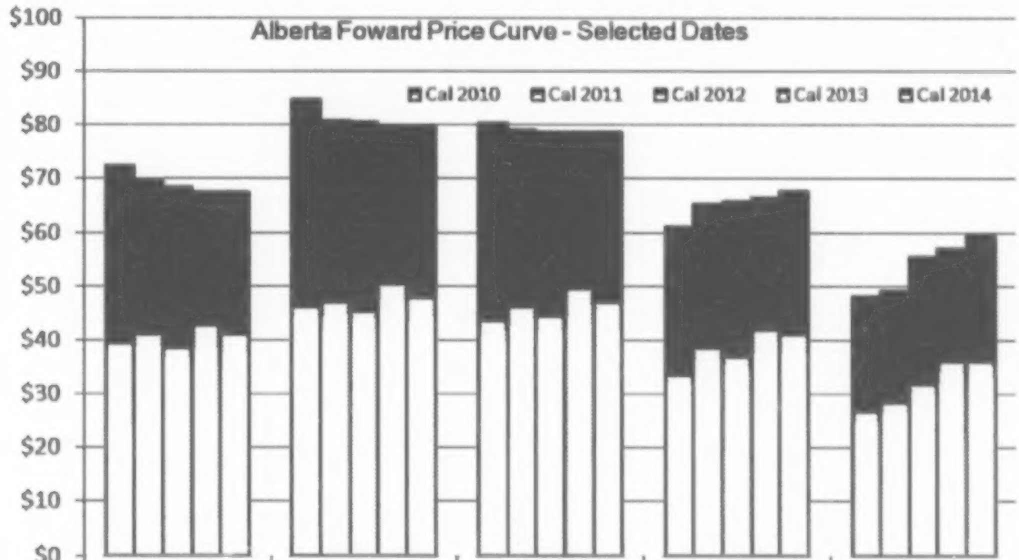
The above analysis substantiates that predicting price by demand levels, including seasonal, daily and hourly profiles, is not effective in Alberta with the current hourly market structure. In fact, the most dominant price drivers in Alberta at present are wind production and un-scheduled coal outages – both very difficult circumstances to forecast.

The result is that it would be difficult for Alberta consumers to be able to capture savings using only the hourly market as a price signal. This is much different from other jurisdictions that have a high correlation between price and demand level. These are typically jurisdictions with electric air conditioning that can be harnessed in the summer for demand response purposes. Alberta does not have this option.

APPENDIX 2: Forward Market

The Alberta forward power market has relatively modest *liquidity* (liquidity measures the volumes traded in forward markets as compared to actual consumption in the spot markets). Some forward power trades occur on the Natural Gas Exchange, but forward power is primarily traded as over-the-counter (OTC) bilateral transactions. The primary product transacted is the 7x24 (7 days per week, 24 hours per day) baseload contract, with limited trades in the 6x16 (Monday through Saturday, 16 hours per day) and 7x16 (all days, 16 hours per day) peak products and off-peak hour instruments.

While most transactions are for products in the current and immediate year-ahead instruments, there are occasional trades and consistent market bids and offers out to 2015. The forward power curve in Alberta is driven by the natural gas forward curve, and generally has nearby prices that are higher than prices for further out periods. Energy commodities that are essentially non-storable, such as power, will demonstrate this form of a price curve due to the availability of price substitutes further into the future and the absence of inventories as price buffers.



	Jan 01 08	Jul 01 08	Jan 01 09	Jul 01 09	Dec 31 09
Cal 2010	$72.50	$84.75	$80.50	$61.00	$48.00
Cal 2011	$70.00	$81.00	$79.25	$65.25	$49.30
Cal 2012	$68.50	$80.75	$78.75	$65.75	$55.75
Cal 2013	$67.50	$80.00	$78.75	$66.50	$57.00
Cal 2014	$67.50	$80.00	$78.75	$67.75	$59.75

Figure 40: Alberta Forward Curve 2008 to 2010

Figure 40 (a repeat of Figure 6) illustrates the Alberta forward curve for selected dates from 2008 to 2010 for the Calendar 2010 to Calendar 2014 products. (Calendar products are baseload contracts for every hour of the year). In January 2008, the forward curve reflected higher 2010 prices than 2014.

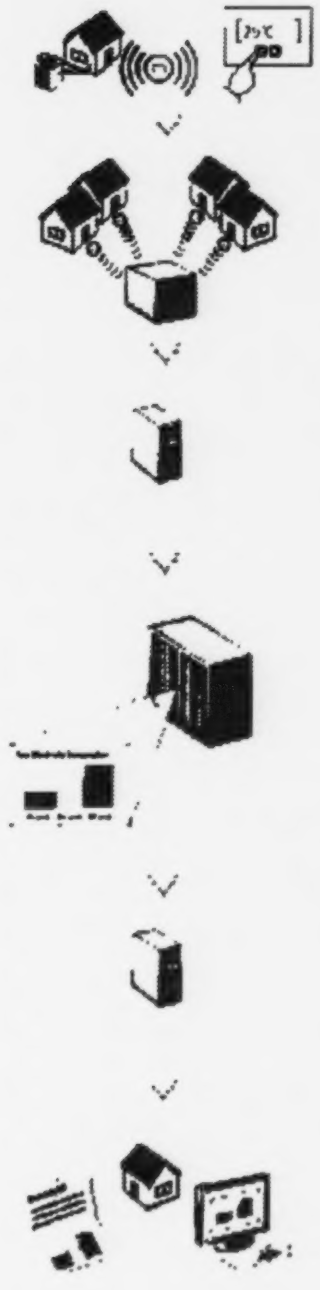
However, in January 2010 the market had switched to having 2010 prices lower than 2014. This was a result of the power curve following the natural gas price curve which reflected the loss of demand due to economic conditions across North America, and the advent of new supplies from vast shale gas reserves that have become recoverable due to use of horizontal drilling techniques.

Although the forward market for power in Alberta is relatively illiquid it does have sufficient transactions to reflect the market's perception of prices and is a reasonable guide to future pricing of power. Unfortunately, the forward market and the spot market, as transacted in the hourly AESO market, do not converge as seamlessly as the forward and spot gas markets do.

Products within one year of dispatch are driven by the expected average hourly prices, which are influenced by the erratic and volatile nature of the hourly market. Prices beyond one year are primarily influenced by the gas prices and expectation of heat rates for gas units. The resultant effect is that price volatility for different duration instruments increases very dramatically as dispatch nears.

As seen in Figure 40, forward prices can change dramatically over a relatively short time. The 5-year curve went from $68/MWh in January 2008 up to $80/MWh by January 2009 and back to $55/MWh by January 2010. This forward curve volatility adds significant risks to new investments that rely solely on energy prices. At $80/MWh price levels, an entire range of generation options can be considered including coal with some form of carbon capture, wind and other renewable, and a suite of co-generation and combined cycle gas facilities. At the current $55/MWh forward prices, almost all of these options are precluded, the exception being co-generation plants that utilize the low natural gas prices and have alternate revenue compensation from steam production.

APPENDIX 3: Further Considerations for AMI



AMI is a precursor to the development of a full "*Smart Grid*" application in Alberta. Smart Grids enable the reduction of overall energy consumption through coordination of generation, transmission and distribution resources to achieve an efficient allocation of resources to meet demand.

The current Alberta electricity structure with de-regulated generation assets and regulated transmission and distribution facilities may require significant changes in order to achieve smart grid benefits. Alberta Energy is expected to develop working papers on smart grid objectives and benefits over the next two years.

Figure 41: AMI Use and Data Management

Additional information on AMI and smart grids is provided as follows:

Automatic Meter Reading (AMR) is the term used to refer to technology that automatically collects consumption, diagnostic, and status data from electric metering devices and transfers this data to a central database for the purposes of billing, troubleshooting, and analyzing. While AMR relates to electricity metering in this instance, similar technology is also used for water and natural gas metering.

Advanced Metering Infrastructure (AMI) is a relatively new term that refers to networks or systems that measure, collect and analyze electricity consumption from advanced devices through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications, customer associated systems and meter data management software. The meters in an AMI system are often referred to as advanced electric meters or smart meters, since they often can use collected data based on programmed logic. An **Advanced Electric Meter** is a new or appropriately retrofitted electric metering device, which:

- Is capable of measuring and recording usage data in time-differentiated registers, generally on an hourly basis, but in more frequent time periods as well;
- Enables electricity consumers, suppliers and service providers to participate in various types of demand response programs; and

- Provides other data and functionality that address power quality and other electricity service issues.

AMI enables two-way communications with the meter, which is more "advanced" than AMR and traditional systems. Meters record and transmit usage information to local data collection systems, using the existing power lines or a radio frequency technology.

The process of AMI use and data management is illustrated in Figure 41. It was originally designed to describe the Ontario Smart Meter initiative; however, it is useful in describing the generic use of AMI:

1. **Measurement**: AMI/smart meters track electricity used at a metering location on an hourly basis.

2. **Data collection**: hourly electricity consumption data is sent by wireless connection or through telephone or power lines to a local data collector on a daily basis.

3. **Data aggregation and compilation**: data collectors relay energy usage information to larger control computers operated by utilities/local distribution companies. The control computers ensure that all the meters have been read and all the necessary information has been captured.

4. **Data Repository**: collected data is transmitted to a provincial data repository. This data will be used to develop comprehensive load profiles, and help develop appropriate pricing regimes for different times of the day (on-peak/off-peak, etc). This database is highly secure and only authorized parties will have access.

5. **Billing**: billing agents will use information from the data repository to prepare customer invoices.

6. **Energy Management**: consumers will have access to their energy-use data through invoicing and web-interfaces to allow for better energy management.

Across North America AMI as a concept is growing in popularity with potential advantages:

[redacted]

- Utilities are no longer required to make periodic trips to each physical location to read meters;
- Electricity billing can be based on real-time (or near real-time) consumption instead of estimates;
- AMI can be a platform for launching electricity conservation programs including time-of-use pricing to reduce system price peaks;
- More accurate data and transparency enables:
    - Accurate load profiling;
    - Better energy management through profile data graphs;
    - A reduced financial burden and responsibility associated with correcting billing errors;
    - Improved electricity procurement through more accurate volumetric data and forecasting;
- Utilities have less accrued expenditure;
- Faster outage detection.

Table 26: Key Advantages of AMI

(Source: IEE White Paper June 2009)

While the reduced labour costs associated with remote meter reading is the most obvious advantage, the impetus for utilities shifting to AMI tends to be the access to accurate, transparent data that can be used to encourage consumer responses to system needs.

APPENDIX 4: Economic Analysis – Selected Northern Alberta Projects

Note that Appendix 4 is provided as a separate document.

APPENDIX 5: References

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